TAMPERE UNIVERSITY OF TECHNOLOGY

LEENA PIRHONEN

EFFECTS OF CARBON CAPTURE ON A COMBINED CYCLE GAS TURBINE

Master of Science Thesis

Prof. Petri Suomala and Prof. Risto Raiko have been appointed as the examiners at the Council Meeting of the Faculty of Business and Technology Management on 17 August 2011.

ABSTRACT

TAMPERE UNIVERSITY OF TECHNOLOGY
Master's Degree Programme in Industrial Engineering and Management

PIRHONEN, LEENA: Effects of Carbon Capture on Combined Cycle Gas Turbine
Master of Science Thesis, 80 pages, 3 appendices (3 pages)
September 2011
Major: Industrial Management
Examiners: Professor Risto Raiko and Professor Petri Suomala
Keywords: Carbon Capture, CCS, CO_2 Capture, Pre-combustion, Combined Cycle Gas Turbine, CCGT

Carbon dioxide capture and storage technologies are developed to answer the growing need to reduce emissions. In the thesis the carbon dioxide capture technologies are studied from the perspective of a greenfield combined cycle gas turbine power plant producing both heat and power. The objective of the thesis was to determine how a carbon dioxide technology affects the power plant. Both thermodynamic and cost effects were studied.

The technologies were first compared, and based on the comparison a pre-combustion technology seemed most appealing from the perspective of a greenfield combined cycle gas turbine power plant. The combined cycle gas turbine power plant producing both heat and electricity with pre-combustion carbon dioxide capture was modeled, and the effects evaluated.

The efficiency of the power plant modeled was 11%-units lower than a corresponding power plant without carbon dioxide capture. The efficiency was higher the lower the carbon dioxide capture rate. The power to heat ratio was 6%-units higher than in a corresponding power plant without carbon capture. The change in the power-to-heat ratio was negligible in the modeled cases, in which carbon dioxide separation rates were 80%, 90%, and 97%. These results were in line with the previous studies.

The investment cost of the power plant was four times higher than the power plant without carbon dioxide capture. Compared to previous studies the cost of avoided carbon dioxide emissions was extremely high.

From the results of the thesis it was concluded that the power plant modeled is not feasible. However, many assumptions had to be made which might not be appropriate and demands further attention.

TIIVISTELMÄ

TAMPEREEN TEKNILLINEN YLIOPISTO
Tuotantotalouden koulutusohjelma

PIRHONEN, LEENA: Hiilidioksidin talteenoton vaikutukset kombivoimalaitokseen
Diplomityö, 80 sivua, 3 liitettä (3 sivua)
Syyskuu 2011
Pääaine: Teollisuustalous
Tarkastajat: professori Risto Raiko ja professori Petri Suomala
Avainsanat: Hiilidioksidin talteenotto, CCS, maakaasukombivoimalaitos

Hiilidioksidin talteenotto- ja varastointitekniikoita kehitetään vastaamaan kasvavaan tarpeeseen vähentää kasvihuonepäästöjä. Tässä työssä hiilidioksidin talteenottotekniikoita tutkittiin uuden lämpöä ja sähköä tuottavan maakaasukombivoimalaitoksen näkökulmasta. Tavoitteena työssä oli selvittää, kuinka hiilidioksidin talteenotto vaikuttaa sekä voimalaitoksen prosessiin että sen kustannuksiin.

Aluksi työssä vertailtiin eri talteenottotekniikoita. Vertailussa ennen polttoa tapahtuva hiilidioksidin talteenottotekniikka vaikutti parhaalta vaihtoehdolta uuden lämpöä ja sähköä tuottavan maakaasukombivoimalaitoksen näkökulmasta. Tekniikka mallinnettiin maakaasukombivoimalaitokseen ja sen vaikutuksia arvioitiin.

Hiilidioksidin talteenotolla varustetun voimalaitoksen hyötysuhde oli 11 %-yksikköä huonompi verrattuna vastaavaan voimalaitokseen ilman talteenottoa. Hyötysuhde oli sitä huonompi, mitä suurempi talteenottoaste oli. Voimalaitoksen rakennusaste puolestaan oli 6 %-yksikköä korkeampi verrattuna voimalaitokseen ilman talteenottoa. Rakennusasteessa ei havaittu merkittävää muutosta mallinnetuilla hiilidioksidin erotusasteilla, jotka olivat 80 %, 90 % ja 97 %. Nämä tulokset olivat hyvin linjassa aiempien tutkimusten kanssa.

Voimalaitoksen investointikustannukset olivat nelinkertaiset vertailulaitokseen nähden. Verrattuna aiempiin tutkimuksiin vältettyjen hiilidioksidipäästöjen hinta nousi diplomityössä erittäin korkeaksi.

Työn tuloksena todettiin, että työssä mallinnetun hiilidioksidin talteenoton soveltaminen lämpöä ja sähköä tuottavaan maakaasukombivoimalaitokseen ei ole kannattavaa. Tulokseen vaikutti työssä tehdyt monet oletukset, joiden parissa todettiin jatkotutkimustarpeita.

PREFACE

For me, the thesis project has most of all been a learning process. It has been rewarding to notice how different parameters affect one another. The scope of the thesis was wide, and I was able to increase my knowledge in many areas of power plant engineering.

The thesis is part of a CLEEN Ltd's CCSP program. The program is funded by the Finnish Funding Agency for Technology and Innovation. I would like to thank Gasum Oy for having given me the opportunity to participate in the program. I would also like to thank my supervisors from Tampere University of Technology, Professor Risto Raiko and Professor Petri Suomala, for all their help and comments.

I would like to thank everyone for the help I received during the process. My supervisor, Sari Siitonen from Gasum Oy, guided me through the thesis project. I appreciate all the advice and comments she gave. From Gasum Oy I would also like to thank Lauri Pirvola, who helped me with the district heating parameters, Arto Riikonen who gave me information about gas technology, and the all the employees for the excellent work environment.

I would also like to thank Timo Laukkanen from Aalto University, who gave me the opportunity to model using the Aspen Plus ® and taught me to use it, Antti Arasto from VTT and Hanna Knuutila from Sintef, who helped me with many problems with the absorber model, Risto Sormunen and Erkki Mäki-Mantila from Fortum Oy, who provided me with valuable information and data about the topic, and Melina Laine from Helsingin Energia, who also did her master's thesis on the topic and gave much needed peer support during the process.

I also thank my husband Antti Pirhonen for the all the support I received.

Helsinki 4 August 2011

Leena Pirhonen

TABLE OF CONTENTS

ABBREVIATIONS AND NOTATION

a	Annuity factor
d	Present value factor
H_{mt}	Enthalpy in certain temperature
i	Interest rate
K_p	Equilibrium constant
M	Molar mass
n	Number of years
N	Amount in moles
p^0	Normal pressure
p_i	Pressure of component i
q	Lower heat value
Q	Reaction enthalpy in reference temperature
q_p	Higher heat value
η_{tot}	Total plant efficiency
ρ	Density
ABS	Absorber
ATR	Auto thermal reformer
AZEP	Advanced zero emission process

C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
C_5H_{12}	Pentane
CC	Combined cycle
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CES	Clean energy systems
CH_4	Methane
CHP	Combined heat and power
CLEEN	Finnish energy and environment competence cluster
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of energy
COND	Condenser
COP	Coefficient of performance
DEA	Diethanolamine
DEA^+	Diethanolamine ion
$DEACOO^-$	Diethanolaminecarbamate ion
DH	District heating
DHW	District heating water

EG	Exhaust gases
EU	European Union
EUA	European Union Allowances (CO_2 emissions)
FWT	Feed water tank
GT	Gas turbine
H^+	Hydrogen ion
H_2	Hydrogen
H_2O	Water
HCO_3^-	Bicarbonate ion
HPS	High pressure steam
HPW	High pressure water
HRSG	Heat recovery steam generator
HTS	High temperature shift
IEA	International energy agency
IFRF	International flame research foundation
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental panel on climate change
IRR	Internal rate of return
LPS	Low pressure steam
LPW	Low pressure water
LTS	Low temperature shift

MDEA	Methyldiethanolamine
$MDEA^+$	Methyldiethanolamine ion
MEA	Monodiethanolamine
MPS	Medium pressure steam
N_2	Nitrogen
NETL	National energy technology laboratory
NG	Natural gas
NO_X	Nitrogen oxides
NPV	Net present value
O_2	Oxygen
OH^-	Hydroxide ion
REF	Reformer
ROI	Return on investment
SG	Synthetic gas
ST	Steam turbine
SWOT	Strengths, weaknesses, opportunities, and threats
TCM	Total cost management
VAT	Value added tax
VTT	Technical Rresearch Centre of Finland

1 INTRODUCTION

Climate change has received attention from scientist since the 19th century when Fourier recognized the warming effect of the atmosphere in 1824 (Fourier, 1836). Concern over climate change has grown in recent decades. It is one of the biggest challenges of our time. Human activities have increased the concentration of greenhouse gases in the atmosphere, which are considered to have a significant impact on the climate. At the same time secure, reliable and affordable energy supplies are needed for economic growth. One of the technologies available to mitigate greenhouse gas emissions from large-scale fossil fuel usage is carbon dioxide capture and storage (CCS). (IEA, 2008)

CCS is expected to play a significant role in reducing emissions from power sector. In Figure 1.1 the key technologies for reducing CO_2 emissions are shown. CCS's contribution is one fifth of the entire reduction plan in the International Energy Agency's (IEA) BLUE Map Scenario for 2050. CO_2 can be captured from a variety of sources including power plants, gas processing, and emission intensive industry. (IEA, 2010)

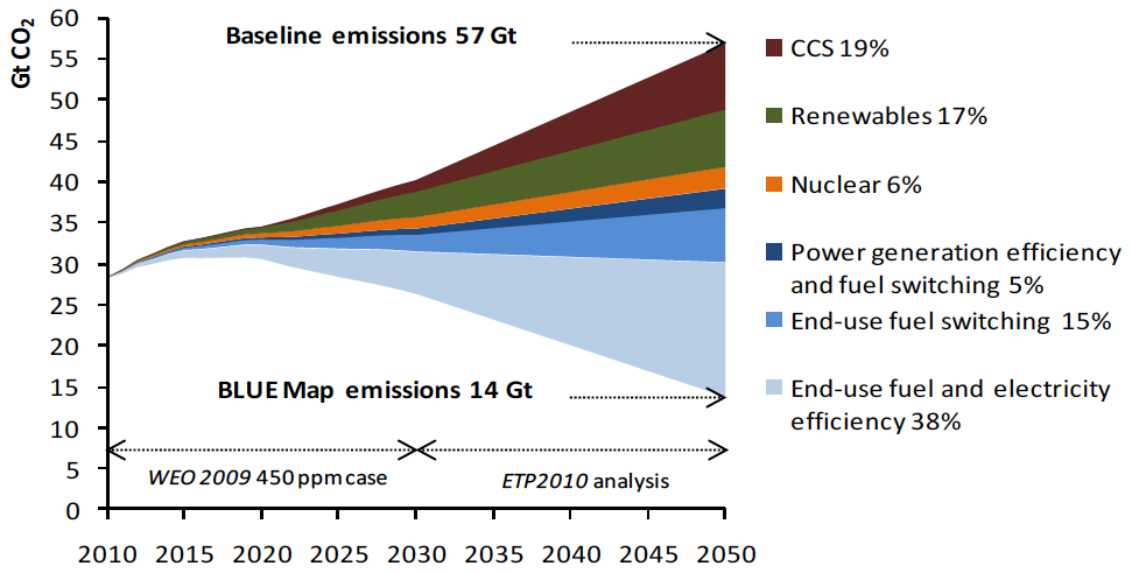


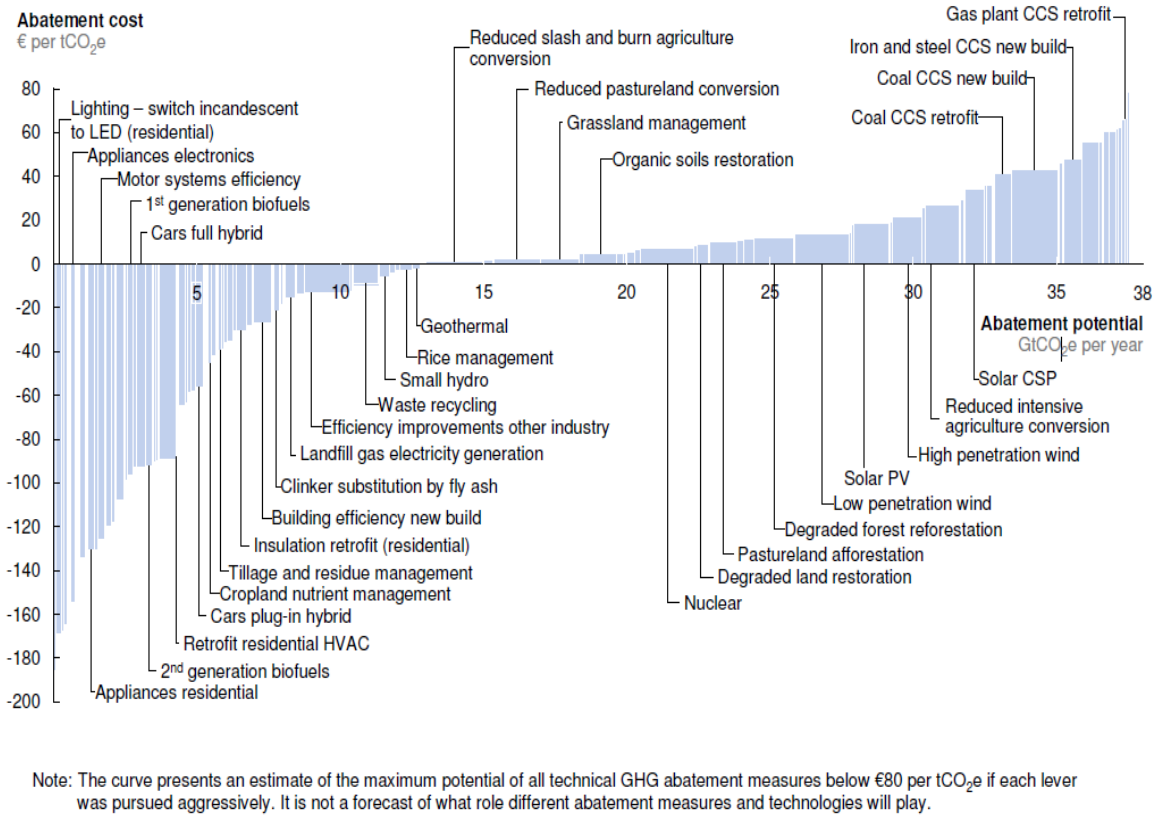
Figure 1.1. *Key technologies for reducing CO_2 emissions (IEA, 2010).*

International policies, such as the Kyoto Protocol and EU directives, aim to mitigate climate change. The Kyoto Protocol is a legally binding agreement under which industrialized countries will reduce their collective emissions of greenhouse gases by

5.2% compared to 1990 in 2008-2012. Further agreement has not yet been accomplished. The European Council's energy and climate change objectives for 2020 are to reduce greenhouse gas emissions by at least 20%, to increase the share of renewable energy to 20% and to make a 20% improvement in energy efficiency. Even though the EU has a directive on the geological storage of carbon dioxide, a clear international regulatory framework on CCS is lacking. (UNFCCC; EU, 2010)

The Kyoto Protocol includes mechanisms to reduce carbon dioxide emissions. One of these mechanisms is emission trading. Emission trading plays a key role in making CCS profitable. The price of an emission allowance should be higher than the cost of CO_2 emissions avoided in order to make CCS profitable. At this point, the prices of the emission allowances do not exceed the costs of CCS. In 2010, the EUA price under the EU Emission Trading System remained between €12/CO_2-tonne and €17/CO_2-tonne (EEX, 2011). Moreover, the price of emission allowance futures for 2015 has been only slightly over €20/CO_2-tonne in 2011 (EEX, 2011).

In Figure 1.2 the costs of different ways to reduce emissions are presented.



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €80 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.

Figure 1.2. *The cost of reduced emissions. (McKinsey, 2010)*

1.1 CCSP Program

The thesis is part of CLEEN Ltd's CCSP program. CLEEN Ltd is a Finnish energy and environment competence cluster owned by companies and research institutes. The overall objective of the CCSP program is to develop CCS related technologies and concepts that aim for pilots and demonstrations to be commercialized by the companies. The thesis is part of subtask 2.1.2 in work package number 2 entitled "CCS in gas turbine power plants". The objective in the subtask is to determine technical and economical solutions for carbon capture in combine heat and power (CHP) gas turbine power plants.

1.2 Objectives of the Thesis

The objective of the thesis is to increase understanding about the effects the carbon capture technologies have on a greenfield combined cycle gas turbine power (CCGT) plant in producing both electricity and heat. The plant is planned to be located in Finland. The main focus is on the process of the power plant, but also the cost effect is evaluated. The effects are examined from the power plant perspective.

The research question of the thesis is as follows:

How does carbon capture affect a new gas turbine combined cycle power plant with combined heat and power production?

The thesis studies how carbon capture affects total plant efficiency, electricity production efficiency, power-to-heat ratio, fuel input, CO_2 emissions, CO_2 avoidance cost, and cost of electricity and heat production. A sensitivity analysis is made.

The transportation and storage element of CCS is excluded from the discussion in the thesis. The exact system limit is drawn to the point where CO_2 is liquefied and ready for ship transportation. The dashed line in Figure 1.3 illustrates this limit. Because of the importance of transportation and storage of CO_2, an overview is presented.

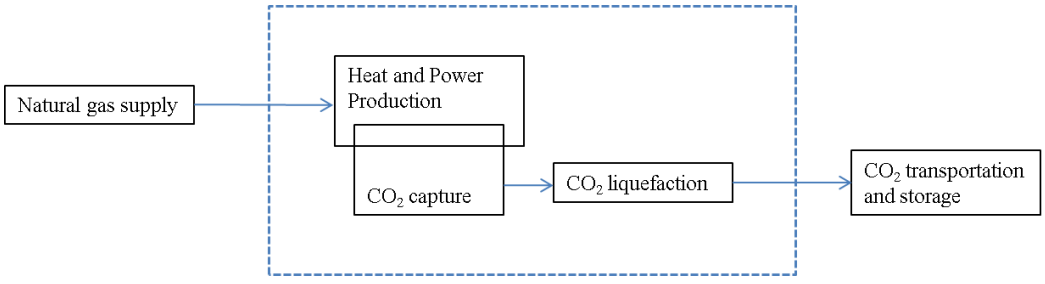


Figure 1.3. *Outline.*

An overview of recent CCS projects and research is presented in chapter 2. Carbon capture technologies are briefly introduced in chapter 3. In addition, an overview of CO_2 transportation and storage is presented. The technologies are then compared from the perspective of the greenfield combined cycle gas turbine power plant producing both heat and power, and the reasons for the technology choice for the case are presented. An overview of cost engineering, when choosing a technology for a power plant, is presented in chapter 4.

In chapters 5 and 6 the assumptions made in modeling are presented. The results of the study are presented and discussed in chapters 7 and 8. Chapter 9 summarizes the results of the thesis.

2 REVIEW OF CCS RESEACRH AND PROJECTS

Carbon capture and storage is widely studied. The European Commission (2007) encouraged the Member States to conduct research and to develop CO_2 capture and storage technologies so that in 2020 it would be feasible to use them in new fossil fuel power plants. The Energy Policy for Europe (2007) states "On the basis of existing information, the Commission believes that by 2020 all new coal-fired plants should be fitted with CO_2 capture and storage and existing plants should then progressively follow the same approach. Whilst it is too early to reach a definite view on this, the Commission hopes to be able to make firm recommendations as soon as possible." The European Commission (2010) created a financial instrument managed jointly by the European Commission, the European Investment Bank, and Member States. This instrument is known as NER300 – Finance for installations of innovative renewable energy technology and CCS in the EU (NER300, 2011). Financing is provided by 300 million emission allowances, which are given without charge for the installations (NER300, 2011).

The projects currently in operation are shown on the map in Figure 2.1. The projects are mainly CO_2 storage projects.

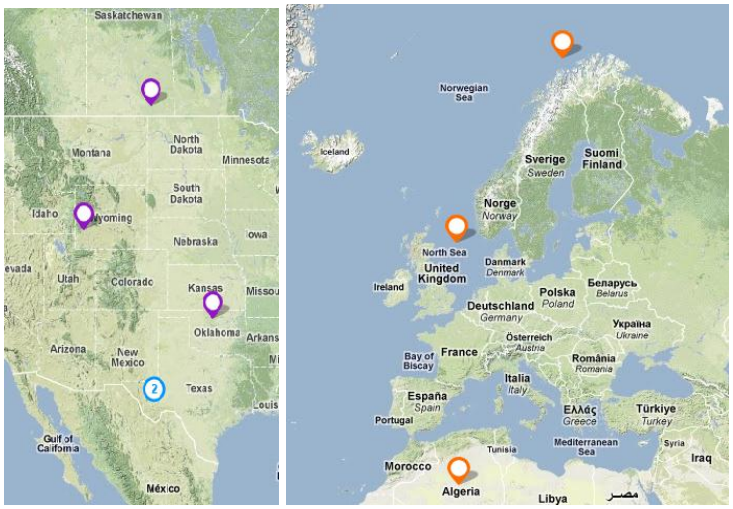


***Figure 2.1**. CCS projects currently in operation. (Global CCS Institute, 2011)*

The projects with an orange label use the captured CO_2 in enhanced gas recovery. The projects with a violet label and the number two label use the captured CO_2 in enhanced

oil recovery. The number two label in the figure above represents the two CCS projects in Texas. Even though there are only a few projects currently in operation, there are several CCS projects in the evaluation and definition phase. This is shown in Figure 2.2. (Global CCS Institute, 2011)

Figure 2.2. *All CCS projects. (Global CCS Institute, 2011)*

Even though the majority of the CCS projects plan to use coal and biomass as a fuel, there are also natural gas fueled projects under way. A gas and coal-fired post-combustion carbon capture pilot plant is due to start operation in 2012 in Technology Centre Mongstad in Norway. The CO_2 separation rate in the plant will be approximately 85%. (TCM, 2011)

There are several integrated gasification combined cycle (IGCC) projects in the UK and in the United States. In these projects solid fuels are first gasified and hydrogen rich fuel is then combusted in a gas turbine unit. Thus, IGCC plants are gas turbine combined cycle power plants. (Global CCS Institute, 2011)

The Don Valley Power Project and CCS project at Peterhead are two natural gas-fired CCS projects in the UK. A pre-combustion carbon capture technology will be used in the Don Valley Power Project. The separation rate in the project is approximated to be 90% (Co2 Energy, 2011). The CCS project at Peterhead is a post-combustion carbon capture project. The carbon capture facilities will be retrofitted into an existing combined cycle gas turbine power plant (SSE, 2011). In addition to the individual projects, Energy Technologies Institute in the UK launched a CCS for gas plant projects (Power Engineering, 2011).

In Finland, CCS has been studied in research projects, e.g. CCS Finland. A coal-fired demonstration plant was also planned by Fortum Oy in Meri-Pori in Western Finland, but the project was cancelled (Fortum, 2010).

3 CO_2 CAPTURE

The production of CO_2 cannot be avoided when hydrocarbon fuels are combusted. To reduce CO_2 emissions, carbon has to be captured. The purpose of CO_2 capture is to produce a concentrated stream of CO_2 at high pressure that can be transported to a storage site. (Rackley, 2010; VTT 2010)

There are currently three primary technologies to reduce CO_2 emissions. The technologies which decarbonize the fuel prior to combustion are known as pre-combustion technologies. In technologies know as post-combustion, CO_2 is separated from flue gases. Combustion can also be re-engineered in such a way that it produces only CO_2 and water that can be condensed after combustion. This capture technology is called oxy-fuel combustion. In oxy-fuel combustion the fuel is combusted in pure oxygen. There is also significant modification of oxy-fuel combustion, known as chemical looping. (Rackley, 2010; VTT 2010)

A number of technologies to separate CO_2 from other gases have been studied. In post- and pre-combustion technologies the technologies are absorption, adsorption, membrane and cryogenic technologies. In oxy-fuel capture technology the CO_2 is separated from steam, as the exhaust gases consist of only CO_2 and steam after combustion with oxygen. The oxygen required is separated from air. These separation technologies include adsorption, membranes and cryogenic technologies. (Rackley, 2010; VTT 2010)

The CO_2 capture technologies are introduced in chapters 3.1, 3.2 and 3.3. In addition, these chapters evaluate the strengths, weaknesses, opportunities and threats (SWOT analysis). SWOT-analysis is a strategic management tool. It helps to evaluate the attractiveness of the business field or, as in this case, the technology. (Haverila et al, 2005).

Transportation and storage of CO_2 is briefly introduced in chapter 3.4. The capture technologies are compared in chapter 3.5.

3.1 Post-combustion

In post-combustion CO_2 capture technology the CO_2 is separated from the flue gases. The main component is typically nitrogen. In this manner, the separation technologies are developed to separate CO_2 from N_2. The technologies used in separation are already used in a wide range of industrial processes, refining and gas processing. Thus, the

technology in itself is mature, but not in CCS usage. However, post-combustion is the most mature CO_2 capture system in the power sector. It can be considered as an extension of the fuel gas treatment for other emissions. Figure 3.1 presents the block diagram for post-combustion CO_2 capture in CCGT. (IEA, 2008; Rackley 2010)

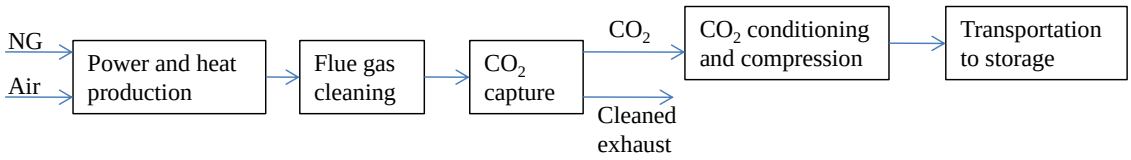


Figure 3.1. *Block diagram for post-combustion CO_2 capture.*

Numerous demonstration projects are expected to use the chilled ammonia process. The research, development and demonstration projects currently focus on new solvents that would consume less energy and reduce the cost of CO_2 capture. Other focuses are on integration of CCS within the power plant and on the procedures for optimal operation under varying plant conditions. (Rackley, 2010; IEA, 2008)

Table 3.1 presents the SWOT analysis for post-combustion technology. As mentioned earlier, the strongest strength of post-combustion technology lies in the maturity of the technology.

Table 3.1. Post-combustion SWOT (Racley, 2010; VTT, 2010; IPCC, 2005; Damen et al, 2006)

Strengths	**Weaknesses**
• Fully developed technology, commercially deployed at the scale in other industry sectors • Simple technology	• High energy demand for regenerating the solvent • May demand significant amounts of process water
Opportunities	**Threats**
• Retrofit to existing plant • Capture readiness	• Slippage of solvent may become a health, safety and environmental issue

3.2 Pre-combustion

Pre-combustion technologies are used commercially in various industrial applications, such as the production of hydrogen and ammonia. Figure 3.2 presents the block diagram for pre-combustion CO_2 capture in CCGT. In a natural gas fueled power plant the fuel must be reformed and sifted to generate a mixture of hydrogen and CO_2. Then, either the CO_2 is removed using sorbents or the hydrogen is removed using membranes. Separation of CO_2 from H_2 is easier than from N_2 due to the greater difference between molecular weights and molecular kinetic diameters. (IEA, 2008; Rackley 2010)

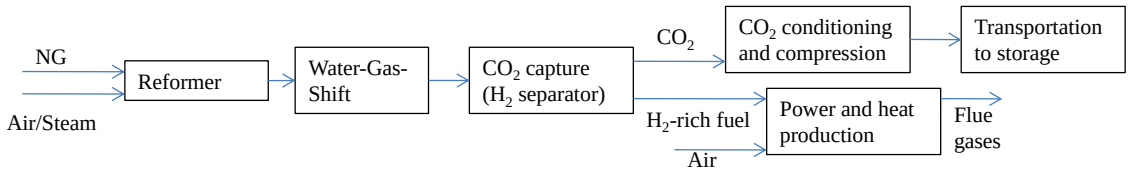


Figure 3.2. *Block diagram for pre-combustion CO_2 capture.*

Currently, the most promising pre-combustion technologies use physical solvents. In physical absorption the bond is much weaker between CO_2 and the solvent than in the chemical absorption. Bonding takes place at high pressure and the CO_2 is released again when the pressure is reduced. Energy is needed to drive the compressors for gas pressurization in the separation system. The energy conversation of the capture technology is higher when the concentration of CO_2 in the flue gases is lower. (IEA, 2008; Rackley, 2010)

The SWOT analysis for the pre-combustion CO_2 capture technology is presented in Table 3.2. The relatively low need of energy in the CO_2 separation is the strongest strength of the pre-combustion technology.

Table 3.2. Pre-combustion SWOT (Racley, 2010; VTT, 2010; IPCC, 2005; Damen et al, 2006)

Strengths	**Weaknesses**
• Relatively high CO_2 concentration before separation→ lower energy demand for CO_2 capture and compression • When increasing CO_2 capture rate, the specific energy requirement does not greatly increase • Separation of CO_2 from H_2 is easier than from N_2	• Temperature and efficiency issues associated with hydrogen-rich gas turbine fuel • Increase of NO_x emissions due to increased flame temperature
Opportunities	**Threats**
• Development of H_2 fueled gas turbine • High development potential owing to the combined power cycle	• Difficult to retrofit • Complex technology has to be used

3.3 Oxy-fuel Combustion

The oxy-fuel process involves the combustion of hydrocarbons in almost pure oxygen, obtained from an air separator unit. Because of different combustion characteristics a different approach to air combustion is required, such as water recycling or flue gas recycling. (IEA, 2008)

The block diagram for oxy-fuel combustion CO_2 capture technology is presented in Figure 3.3. First, the oxygen is separated from the air, which is used to burn natural gas. The flue gases from the combustion contain mainly water and CO_2. Part of the flue gases is recycled back to the process and part of it is conducted to CO_2 separation. The CO_2 is separated by condensing the water in the flue gases.

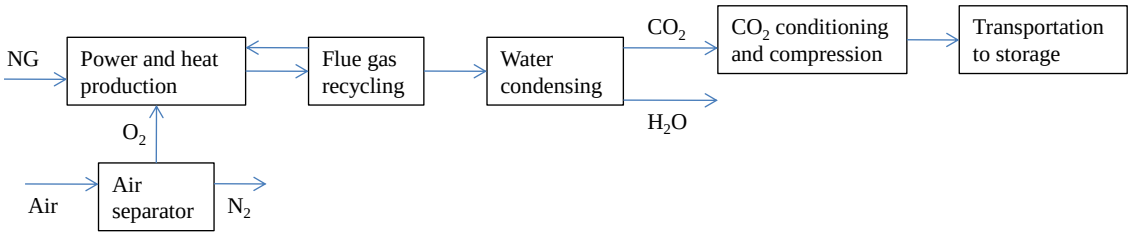


Figure 3.3. *Block diagram for oxy-fuel combustion CO_2 capture*

Chemical looping is a promising variant of oxy-fuel capture technology. In this process, calcium compounds or metal compounds are used to carry oxygen and heat between successive reaction loops. In the gas turbine application the fuel oxidation reactor replaces the conventional combustion chamber. The CO_2 is separated as in regular oxy-fuel technology. Chemical looping is still at a very early stage of development and has been the subject of laboratory-scale experiments. (IEA, 2008; Rackley 2010)

The SWOT analysis for the oxy-fuel combustion system, which includes chemical looping is presented in Table 3.3. In the table chemical looping is regarded as a development opportunity in oxy-fuel combustion.

Table 3.3. Oxy-fuel combustion SWOT (Racley, 2010; VTT, 2010; IPCC, 2005; Damen et al, 2006)

Strengths	**Weaknesses**
• Mature air separation technologies available	• Least mature technology • Production of oxygen consumes energy and is expensive
Opportunities	**Threats**
• Chemical looping • Combination with other capture systems	• Difficult to retrofit

3.4 CO_2 Separation

The most advanced CO_2 separation technology is chemical absorption. Other currently studied separation technologies are physical absorption, physical and chemical adsorption, membrane separation, and cryogenic and distillation. (Rackley, 2010)

In chemical absorption, chemical compounds between the solvent and CO_2 are formed in an absorber. The distillate is released from the top of the absorber tower and the CO_2 rich solvent from the bottom. The absorption reaction is exothermic. In an exothermic reaction energy is released. The reaction is then reversed in the stripping process, which requires heat. In physical absorption, chemical compounds are not formed. The solvent in physical absorption is chemically inert and absorbs the CO_2 without a chemical reaction. (Rackley, 2010)

The difference to absorption in adsorption CO_2 lies in the surface of the sorbent. In absorption it enters the solvent. In both absorption and adsorption of CO_2 a chemical bond or a weaker physical attractive force can be formed. (Rackley, 2010)

Membranes separate CO_2 from gas stream by filtering. The filtering process can involve a number of different physical and chemical processes. The key characteristic of membranes is the porosity. They can be either porous or non-porous. In porous membranes, a permeate is transported through the membrane by molecular sieving. In non-porous, the transport mechanism is called a solution-diffusion. (Rackley, 2010)

Cryogenic separation technology is based on distillation. In distillation, the separation of a mixture of liquids into its components depends upon the difference in the boiling points and volatilities of the components. (Rackley, 2010)

3.5 CO_2 Transportation and Storage

Captured CO_2 has to be transported to the storage site. The transportation cost has a strong impact on the overall cost of CCS. Distances from a power plant to a potential geological storage site can be up to 1,000–1,500 km in Finland (VTT, 2010).

The transportation methods that have received attention in the literature are pipeline and ship transportation. Other transportation methods do not have sufficient capacity to transport the amount of CO_2 captured from a power plant. Transportation of CO_2 by pipeline is a mature technology. It has been in use in enhanced oil recovery in the United States since the 1970's. The factors that affect the cost and safety of pipeline transportation are well known. (VTT, 2010)

At the storage location, CO_2 has to be stored for several thousand years in isolation from the atmosphere. The long storage time adds an uncertainty to all storage technologies. Because of the large amount of CO_2, there are only few possible storage options. To date, only storage in underground geological formation has been demonstrated on a large scale. These geological formations are, for example, oil fields or gas fields. (VTT, 2010)

Another promising storage option is mineral carbonization. Mineral carbonization is binding the CO_2 with silicate minerals into solid carbonates. Currently, is it not viable because of its high energy consumption. (VTT, 2010)

One of the difficulties in transportation and storage of CO_2 is the lack of international regulations. However, the EU has implemented a directive concerning CO_2 storage within the EU. According to the directive, a permit is required for storage. The operating party remains responsible for storage site monitoring, maintenance and reporting also after the storage site is closed. The directive also requires that the purity of the CO_2 stream is high. (EU, 2009) Possible storage locations for CO_2 produced in Finland are in Norway (VTT, 2011). Even though Norway is not part of the EU, it can be assumed to have similar regulations.

3.6 Comparison of CO_2 Capture Technologies

The technology for the case study of the thesis has been chosen by comparing the technologies from a new CCGT CHP plant perspective. Important factors in the comparison are net plant efficiency and maturity of the technology. The SWOT analyses presented in previous subchapters have also influenced the decision. Because the thesis is part of a larger project, the demands of the project have also been taken into account when selecting the case.

According to the results of the SWOT analysis in chapter 2, pre-combustion technology seems appealing from the new CCGT CHP plant perspective. Pre-combustion technologies are mainly more mature than oxy-fuel technologies. In the pre-combustion cases, the energy penalties are lower than in post-combustion cases. The VTT's report also mentions that the development potential in pre-combustion is high in combined cycle applications. (VTT, 2010; Rackley, 2010; IPCC, 2005; Damen et al, 2006)

The separation technologies used in capture systems are presented in the Table 3.4. The table provides an overview of all the separation techniques studied. (Rackley, 2010; VTT 2010)

Table 3.4. Separation technologies. (Rackley, 2010)

	Post-combustion CO_2 separation from N_2	**Pre-combustion** CO_2 separation from H_2	**Oxy-fuel combustion** O_2 separation from N_2
Absorption	Chemical solvents (e.g. MEA, chilled ammonia)	Physical solvents (e.g. Selexol, Fluor process), Chemical solvents	
Adsorption	Zeolite and activated carbon molecular sieves, Carbonate sorbents, Chemical looping	Zeolite, Activated carbon, Hydrotalcites and silicates	Zeolite and activated carbon molecular sieves, Perovskites and chemical looping
Membranes	Polymeric membranes, Immobilized liquid membranes, Molten carbonate membranes	Metal membrane WGS reactors, Ion transport membranes	Polymeric membranes, Ion transport membranes, Carbon molecular sieves
Cryogenic	CO_2 liquefaction, Hybrid cryogenic + membranes	CO_2 liquefaction, Hybrid cryogenic + membranes	Distillation

The results of three different studies comparing CO_2 capture technologies are presented in Figure 3.4. The red triangles are from NETL's report (2010), the green squares are from Damen et al (2006), and the blue diamonds are from Kvamsdal et al (2006). Even though the Kvamsdal et al (2006) article referred to here was published about the same time as the Damen et al (2006) article, Damen et al uses as a reference an earlier presentation from Kvamsdal et al (2004), which is almost the same as Kvamsdal et al (2006). NETL's report (2010) uses both Damen et al (2006) and Kvamdal et al (2007) as references. Below are the explications for the designations in the figure.

Post 1 is reference case 2 from NETL's report (2010) using Fluor Econamine FG Plus^{SM} absorption technology.

Post 2a, **2b** and **2c** are post-combustion cases 1a, 1b and 1c from NETL's report (2010). In all three cases monoethanolamine (MEA) absorption technology is used. In post 2a 35% of exhaust gas is recycled, in post 2b 50% of the exhaust gas is recycled, and in case post 2c 35% of the exhaust gas is recycled and a reboiler is used.

Post 3a and **3b** are post-combustion cases from both (a) Damen et al (2006) and (b) Kvamsdal et al (2006) using MEA absorption technology.

Pre 1a and **1b** are pre-combustion (a) case 2 from NETL's report (2010) and (b) case entitled ATR from Kvamsdal et al (2006). Natural gas is reformed in an autothermal reformer (ATR). CO_2 is removed in a methyldiethanolamine (MDEA) absorption process.

Pre 2 is case 3 from NETL's report (2010). The difference to case pre 1 is that natural gas is reformed in a high-pressure partial oxidation reactor. The CO_2 separation technology is the same MDEA absorption.

Pre 3a and **3b** are pre-combustion cases from (a) Damen et al (2006) and (b) Kvamsdal et al (2006). In both cases membrane separation technology is used.

Oxy 1a and **1b** are oxy-fuel combustion cases that use an air separation unit (ASU) and exhaust gas recycling from (a) NETL's report (2010) case 4 and (b) case entitled oxyfuel CC Kvamsdal et al (2006).

Oxy 2 is case 5 from NETL's report (2010). It uses technology developed by Clean Energy Systems (CES).

Oxy 3a, **3b** and **3c** are oxy-fuel combustion cases using an advanced zero emission process (AZEP) technology from (a) Damen et al (2006) and (b,c) Kvamsdal et al (2006). Cases 3a and 3b separate 100% of CO_2 and case 3c 85% of CO_2.

Oxy 4a and **4b** are chemical looping cases from (a) Damen et al (2006) and (b) Kvamsdal et al (2006).

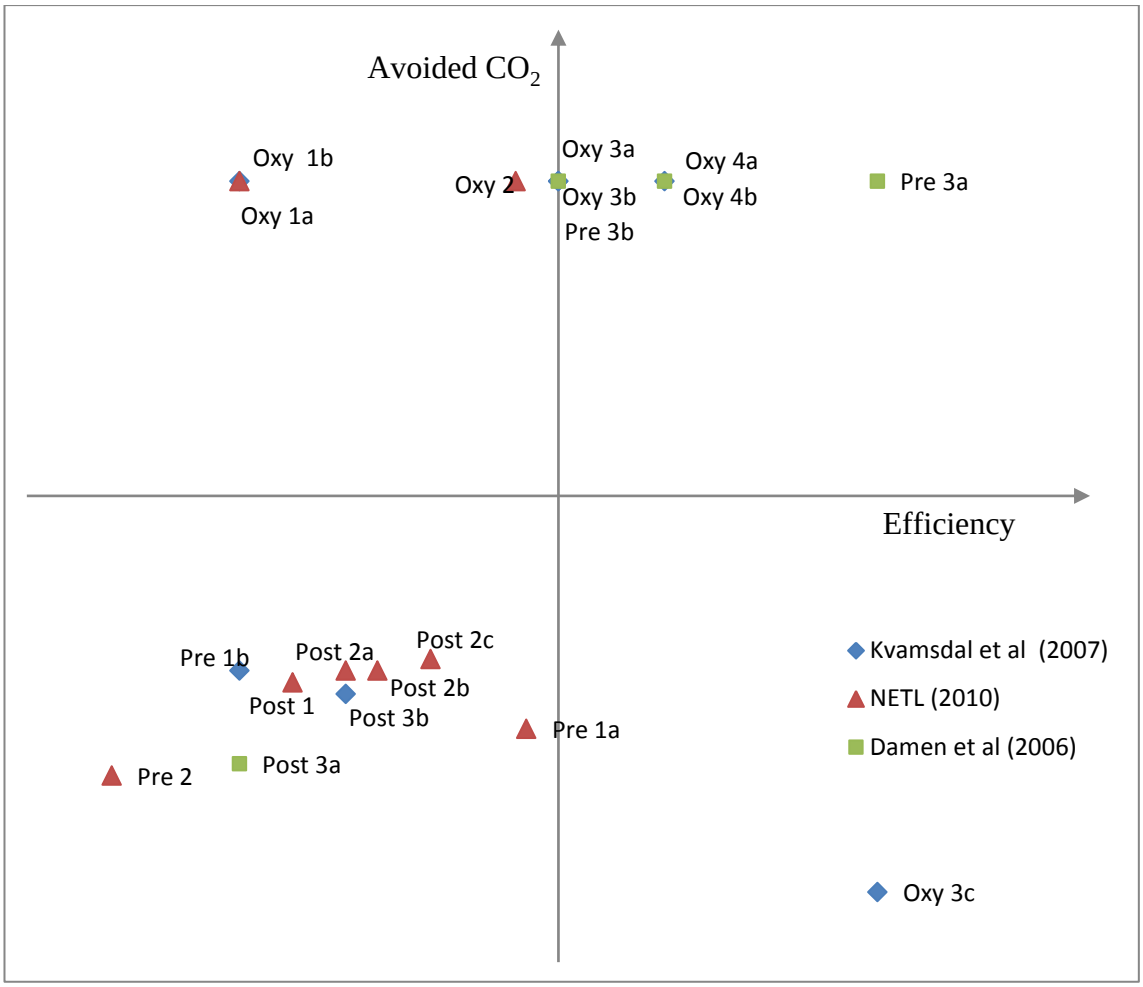


Figure 3.4. *Comparison between capture technologies. (Based on Kvamsdal et al, 2006; Damen et al, 2006; NETL, 2010)*

The parameters in Figure 3.4 are avoided CO_2 emissions and efficiency. The best case is pre-combustion case 3a, which uses a membrane separation technology. Cases pre 3a and pre 3b are similar cases. However, Damen et al (2006) have estimated the efficiency of the case higher than have Kvamsdal et al (2006).

As shown in Figure 3.4, the results in the study Damen et al (2006) are more optimistic than in the other two studies. Pre-combustion efficiencies and avoided CO_2 emissions, especially, are lower in NETL's report. This might be explained by the factors that are taken into account in the studies. In NETL's report more attention is given to the costs and more precise data about the materials are introduced. Kvamsdal et al (2006) do not take account the cost factor. In NETL's report (2010) costs play a significant role. The costs of avoided CO_2 emissions in cases from NETL's report (2010) are presented in Figure 3.5. The intersection of the vertical axel is at a lower efficiency in Figure 3.5 than in Figures 3.4 and 3.6. Figure 3.5 shows that the oxy-fuel combustion technologies are more expensive than post- and pre-combustion technologies.

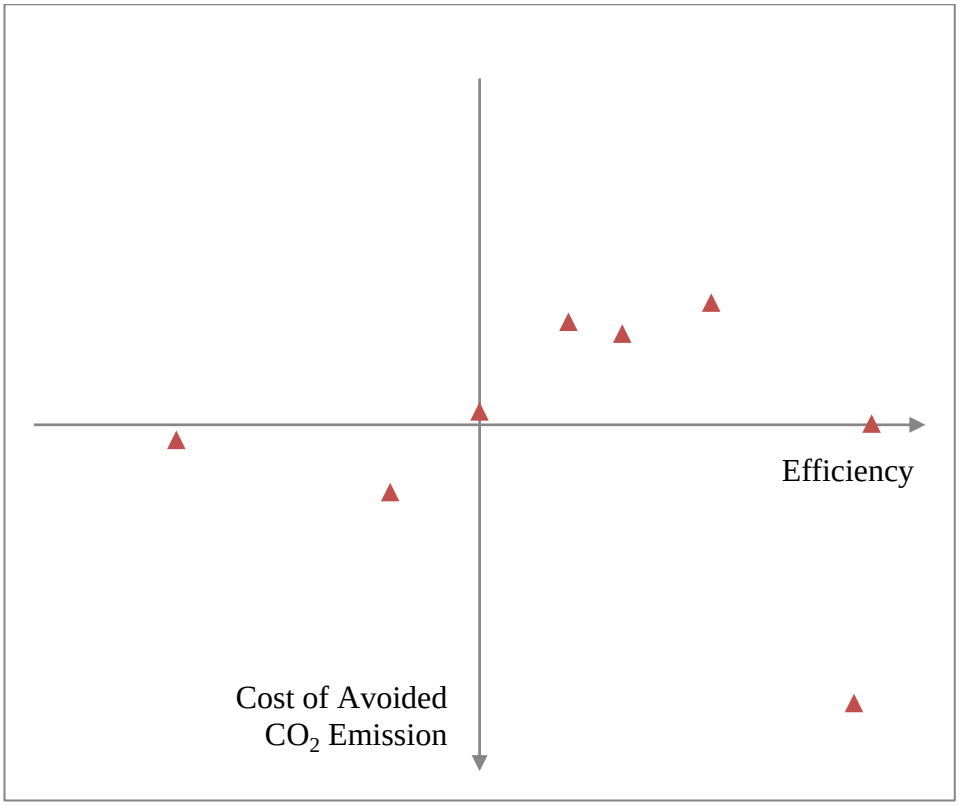


Figure 3.5. *Cost of avoided CO_2 emissions (Based on NETL, 2010)*

In addition to the factors mentioned above, the maturity of the technology is an important factor when selecting the case for the modeling part of the thesis. In NETL's report (2010) all the cases, except case post 1 (reference case 2 in NETL's report), are estimated to need 6–10 years of development. Case post 1 has already been demonstrated. Figure 3.6 presents the maturity of the cases from Kvamsdal et al (2006).

As shown in Figure 3.6, the most mature technologies have the lowest efficiency. There can be at least two explanations for this trend. First, it can be assumed that the development of the technologies with better efficiency has started later, and that is why they are still at an earlier development stage. Another reason for the trend might be that as development progresses, the realities have to be taken into account and more factors appear, which lowers the efficiency.

The three studies compared above support the result from the SWOT analysis. The results favor the selection of pre-combustion technology for analysis in the case study. Because it is important for the thesis to have reliable information about the chosen technology, a mature pre-combustion technology has been chosen.

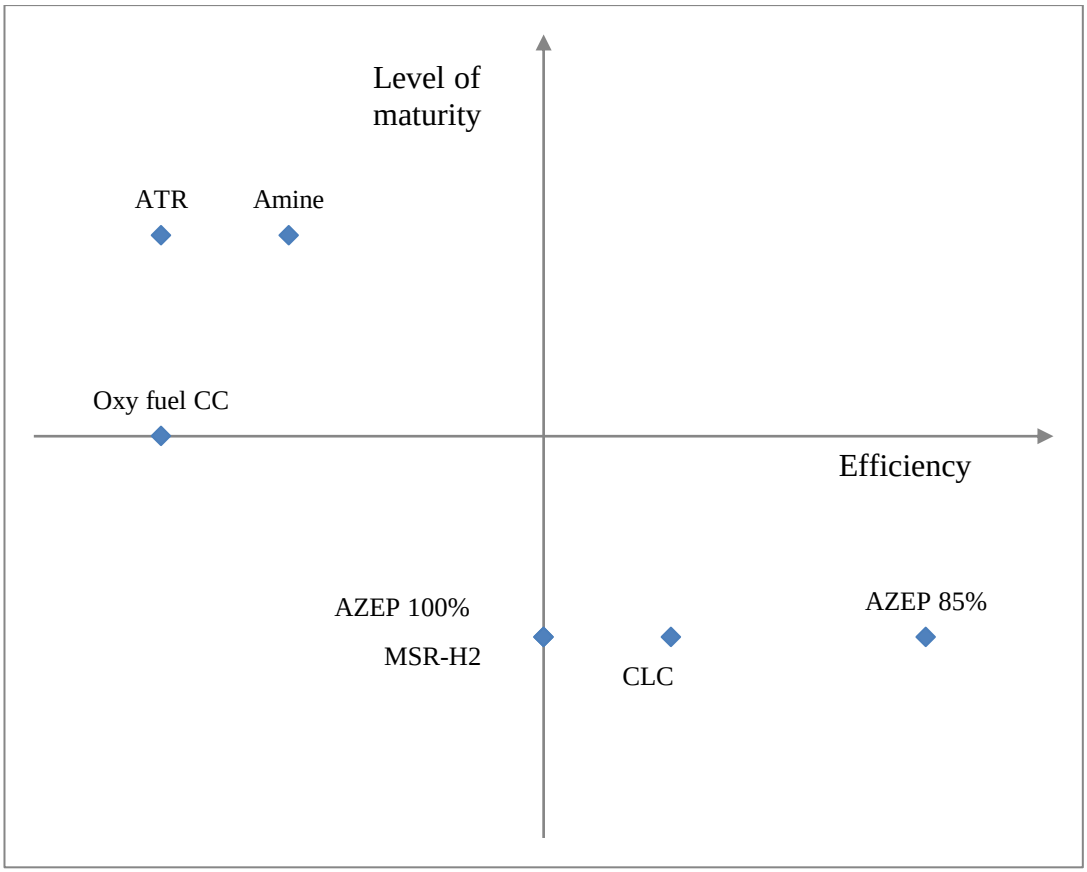


Figure 3.6. *Level of maturity. (Prepared based on Kvamsdal et al, 2006)*

The most mature pre-combustion technology involves an ATR reactor. Air-blown ATR reactors are well suited to integration with a combined cycle for two reasons. First, air entering the ATR can be extracted from the gas turbine compressor. Second, final fuel is diluted with nitrogen, which reduces the NO_x emissions to an acceptable level. This reduces the previously mentioned weakness that pre-combustion technologies have. (Corradetti and Desideri, 2005)

4 ENERGY ECONOMICS

The main principles of energy economics are introduced first in this chapter. Later in the chapter, calculation methods used in the thesis are presented.

The American Association of Cost Engineers defines cost engineering as "the area of engineering practice where engineering judgment and experience are used in the application of scientific principles and techniques to problems of business and program planning, cost estimating, economic and financial analysis, cost engineering, program and project management, planning and scheduling, cost and schedule performance measurement, and change control". The list of practice areas is collectively called cost engineering, while the process through which these practices are applied is called total cost management or TCM. (AACE, 2011)

Neilimo and Uusi-Rauva (2007) define the role of cost engineering to ensure affordable realization of a project. This includes cost estimating, project budgeting, schedule and cost optimization, cash flow calculations, cost reporting and control decisions. As in all projects, energy projects, too, are dominated by scarcity, unless they are designated for a demonstrative or experimental purpose. Scarcity refers to an economic problem or to having limited resources. (Neilimo & Uusi-Rauva, 2007; Vanek, 2008)

The economics of energy production includes the initial cost of the components of the power plant, operating costs, and the price of electricity and heat when sold on the markets. The cost of the components of the power plant and part of the operating costs, e.g. wages, constitute the fixed costs of the power plant. The remainder of the operating costs, e.g. fuel, are called variable costs. Variable costs depend on the operating rate, on which fixed costs do not depend. The major factors that influence the costs are government incentives, capital costs which include construction costs and financing, fuel costs, and air emissions controls for coal and natural gas plants. The relationship between power plant investment and society's collective choices is important because excessive investment or underinvestment can both lead to higher energy costs for the public. (Kaplan, 2008; Vanek, 2008)

The demand for electricity and heat is not constant. The operating time of the plant depends on the demand it is planned to meet. Duration curves (see Figure 4.1) illustrate how much electricity is needed and for how long. Base load power plants operate almost all the time at full load. The best example of a base load plant is a nuclear power plant. Its high investment cost and low operating costs support the high peak load hours.

A CCGT power plant can be used as intermediate load and base load power plants. The investment cost for a CCGT plant is relatively low and partial load use is possible. The main features of peak load power plants are low investment cost and high operation cost. An example of a peak load power plant is a diesel generator. (Kehlhofer et al, 1999)

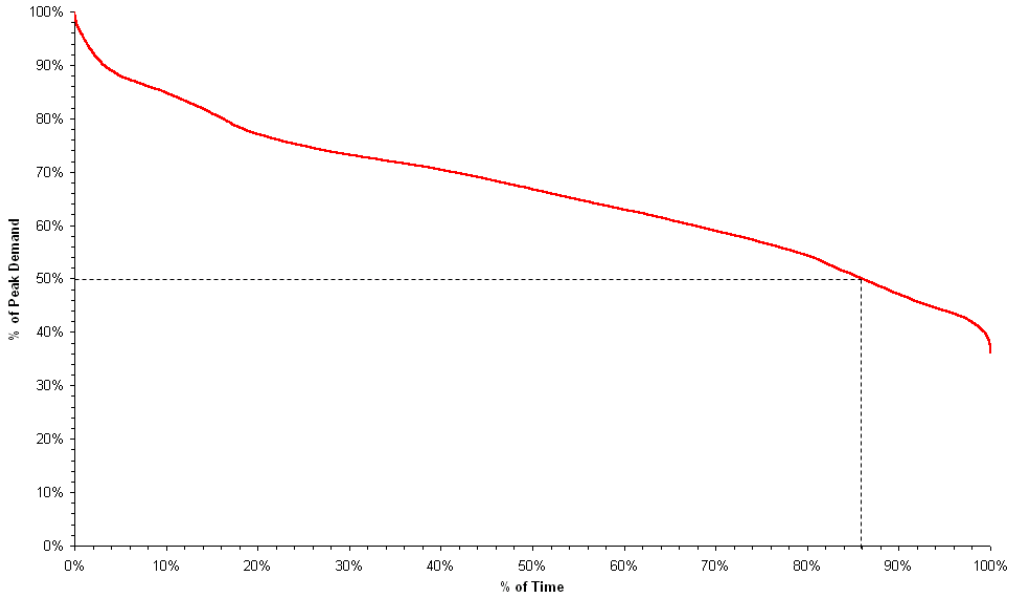


Figure 4.1. *Load duration curve. (National Grid, 2006)*

There are many methods to estimate the cost of a power plant investment. For example, the cost can be roughly estimated by size or some other rule of thumb method (Neilimo & Uusi-Rauva, 2007). Cost estimation methods and accuracies are presented in Appendix 1. In the table the estimation methods are categorized by the phase of the estimation cycle. The table is used in estimating the accuracy of the calculations. In the thesis, the power plant is hypothetical and not all the data needed for a complete cost estimation is available. Thus, many assumptions are made. Only the magnitude of the costs can be calculated.

4.1 Efficiency and Power-to-Heat Ratio

The efficiency of the power plant is a major factor influencing the costs of produced energy. The investment cost of the power plant strongly influences its feasibility, especially when the operation rate is low. However, the core factors are usability and efficiency. Besides operation hours, failures and availability also affect usability. (IFRF, 2002)

Good efficiency is not only an economic factor. Improvement in efficiency also lowers the emissions. The better the efficiency, the more energy can be produced with the same

amount of fuel. From a cost point of view, efficiency could be calculated strictly as the ratio of energy sold to the fuel purchased in energy units in a specific time range.

$$\eta_{tot} = \frac{Electric\ Power\ Sold + District\ Heat\ Sold}{Purchased\ Natural\ Gas} \quad \text{(Equation 1)}$$

where η_{tot} is the overall efficiency of the power plant. It is assumed that all electricity that is not consumed by the plant can be power sold on the power markets.

Overall efficiency of the power plant will be calculated in the thesis as shown in equation (1). In the thesis, the auxiliary electricity consumption is subtracted from the total produced electricity. Also the heat produced to the reformer and absorber (explained in detail in chapter 5.2) is not calculated in the heat power output.

The advantage of presenting efficiency, as in equation (1), is that it represents how well the fuel can be converted into products to be sold. If the efficiency increases, more heat and power can be produced with the same amount of fuel. Conversely, more fuel is needed to produce the same amount of heat and power if the efficiency decreases. However, efficiency cannot be increased endlessly. Higher efficiency usually requires more expensive equipment.

Besides investment cost and efficiency, another interesting factor influencing the feasibility of the power plant is the power to heat ratio. However, if the prices of heat and electricity are almost the same, power to heat ratio has no effect. The equation for the power to heat ratio is presented in equation (2). The same values of electricity and heat are used as in the energy efficiency equation.

$$Power - to - Heat\ Ratio = \frac{Electric\ Power\ Sold}{District\ Heat\ Sold} \quad \text{(Equation 2)}$$

Both power and heat are forms of energy converted from the energy of the fuel. Energy efficiency represents how well this can be done. However, energy efficiency does not differentiate between the values of these energies. The value of the energy represents how well the form of energy can be converted into another form. For example, electricity can be converted into heat almost with 100% efficiency, but heat cannot be converted into electricity as efficiently. This value of energy is called exergy. (VTT, 2004)

Heat and power production is worth combining when its cost is lower than producing them separately. Because the advantage is achieved by combining the productions, it is logical to require that the advantage is divided for both heat and power. The guideline for the division of the advantage should not exceed the costs of alternative electricity

production that is not combined with heat production, and vice versa, should not exceed the cost of alternative heat production costs. (VTT, 2004)

In addition to the guideline described above, there are many ways to divide the advantage gained from combined production. For example, the advantage can be divided based on the amount of energy or exergy, the ratio between the costs of the separate productions, or the ratio between the prices of electricity and heat. (VTT, 2004)

The method used in the thesis is based on the energy method. However, the proportion of costs allocated to heat is the produced heat multiplied by 0.9. The remainder of the costs are allocated to electricity. This is due to the tax regulations. The proportion of natural gas that is used in electricity production is tax-free. Taxes have to be paid on the proportion that is used in heat production. In Finnish regulations, the proportion of natural gas on which taxes have to be paid is the heat produced multiplied by 0.9 (Tullihallitus, 2011). To ensure the coherence of the methods, this coefficient is also used in cost allocation.

4.2 Feasibility of the Investment

There are many ways to compare investment feasibility. In the net present value (NPV) method, all elements of the financial analysis are discounted back to their present worth. The internal rate of return (IRR) indicates the rate of return when the net present value is zero. The return on invest (ROI) method is a simplified version of IRR. ROI is calculated by dividing the profit of a typical year by the investment. The annuity method can be considered as a reversed NPV method because it divides the investment cost equally for the years the investment is operative. The payback time method calculates the length of the payback time for the investment. (Neilimo & Uusi-Rauva, 2007; Vanek & Louis, 2008)

In the thesis, the net present value method is used in investigating the feasibility of the invetment. NPV is chosen because it gives a simple limit for the feasibility of the investment. The changes in feasibility can easily be investigated by keeping the NPV as zero and changing variables affecting it. It takes into account all the parameters needed in the case and is easy to calculate. Net present value is calculated by adding together all the revenues and costs incurred by the investment in present value. If the net present value is positive, the investment is feasible. The present values are calculated with a present values factor. The present value factor is calculated from the interest rate as follows:

$$d = \frac{1}{(1+i)^n} \qquad \text{(Equation 3)}$$

where d is present value factor, i is interest rate, and n is the year when the cost or revenue is expected. (Neilimo & Uusi-Rauva, 2007)

4.3 Costs of Energy and Avoided CO_2 Emissions

Cost of energy (COE) is an annuity method to calculate costs. The cost of energy method combines all cost factors into a cost per unit measure. The calculation of COE is presented in equation 4. The cost of electricity and the cost of heat are calculated from the COE by using the method described in the previous chapter.

$$\mathrm{COE} = \frac{\text{total annual cost (€)}}{\text{annual output (MWh)}} \qquad \text{(Equation 4)}$$

Total annual cost includes the annualized capital cost and operating cost. The operating cost includes the cost of natural gas, solvents, raw water, wages, and maintenance. The annualized capital cost is calculated using the interest rate for the project's lifetime.

An annuity factor is calculated as follows:

$$a = \frac{i\,(1+i)^n}{(1+i)^n - 1} \qquad \text{(Equation 5)}$$

where a is the annuity factor, i is interest rate, and n is the lifetime of the investment. Annuity is the investment multiplied by the annuity factor. (Neilimo & Uusi-Rauva, 2007) The annual costs are shown in Table 4.1.

Table 4.1. Total annual costs (VTT,2004)

Annualized capital cost
+ fixed operating cost (wages and maintenance)
= annual fixed costs
+ variable operating costs (natural gas, solvents, raw water) multiplied by yearly operating time
= total annual costs

Annual costs are also needed when the cost of avoided CO_2 emissions are calculated. The calculation method for the cost of avoided CO_2 emission is shown in Table 4.2.

Table 4.2. Cost of avoided CO_2 emissions.

Total annual costs
– Total annual costs in reference plant
Difference in total annual costs
/ The amount of avoided CO_2 emissions
Cost of avoided CO_2 emissions

Emissions are also calculated per heat or electricity produced. In the case of heat, all the CO_2 emissions are divided by the heat produced. Correspondingly, in the case of electricity, all CO_2 emissions are divided by the electricity produced.

5 POWER PLANT ASSUMPTIONS

The power plant models are introduced in this chapter. Both CCGT CHP with and without CO_2 capture are modeled. The power plant without CO_2 capture is modeled with Solvo ®, presented in chapter 5.3.

The power plant with CO_2 capture is built with three programs. This is presented in chapters 5.1 and 5.2. The base components of the power plant are modeled with Solvo ®. The reforming process is modeled with Microsoft Excel ®. The absorption system is modeled with Aspen Plus ®. The limits and integration between the programs are presented in Figure 5.1. The diagrams of the model from the modeling programs Solvo ® and AspenPlus ® are presented in appendices 2 and 3, respectively.

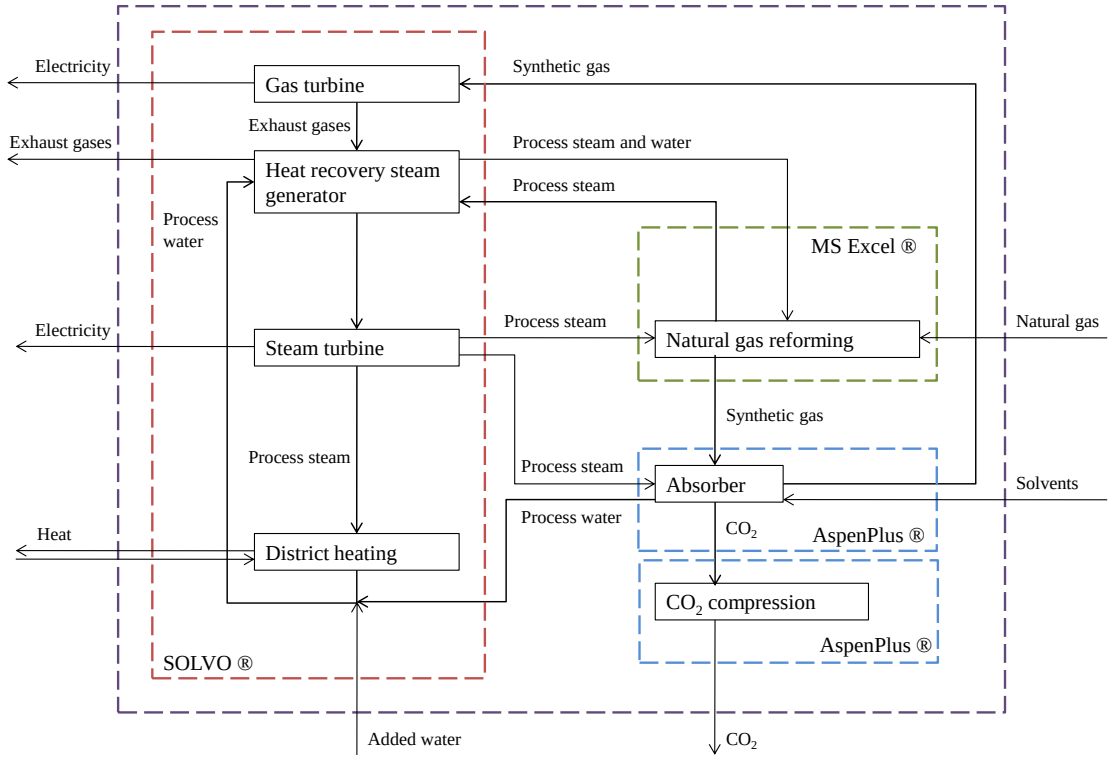


Figure 5.1. *Power plant model.*

The model and the assumptions made in modeling are presented in this chapter. The assumptions are based on the literature and information available in the programs. Solvo ® is a power plant design and optimization tool developed by Fortum Oyj (Fortum, 2011). Aspen Plus ® is a process tool for design, optimization and performance monitoring for the chemical, polymer, specialty chemical, metals and minerals and coal

power industries (Aspen Tech, 2011). Microsoft Excel is a tool to create and format spreadsheets (Microsoft, 2011).

5.1 Combined Cycle Gas Turbine Power Plant

The combined cycle gas turbine power plant modeled is introduced in this chapter. The system consists of two gas turbines, two heat recovery steam generators, and one steam turbine. The fuel used is natural gas that is reformed in a natural gas reformer. The heat load is 350 MW. The power plant is located by the sea, thus cooling water is always available.

5.1.1 Fuel – Natural Gas

Natural gas used in Finland comes from West-Siberia's natural gas fields. The formulation and properties of the gas is shown in Table 5.1. The values in Table 5.1 are average values from measured values in 1 October 2004–31 May 2011 (Gasum, 2011).

Table 5.1. Formulation and properties of natural gas used in Finland. (Based on Gasum, 2011)

Formulation		mol-%	M (g/mol)
	CH_4	98.09	16.04
	C_2H_6	0.76	30.07
	C_3H_8	0.28	44.10
	C_4H_{10}	0.08	54.09
	C_5H_{12}	0.01	72.15
	N_2	0.79	28.01
	CO_2	0.04	44.01
Lower Heat Value	q	36.01	MJ/m^3
Higher Heat Value	q_p	39.94	MJ/m^3
Density	ρ	0.73	kg/m^3n
Molar Mass	M	16.35	g/mol

When natural gas is combusted in air, the combustion reaction are as follows:

$CH_4 + 2\ O_2 + 7.54\ N_2 \rightarrow CO_2 + 2\ H_2O + 7.54\ N_2$ (Reaction 1)

$C_2H_6 + 3.5\ O_2 + 13.195\ N_2 \rightarrow 2\ CO_2 + 3\ H_2O + 13.165\ N_2$ (Reaction 2)

$C_3H_8 + 5\ O_2 + 18.85\ N_2 \rightarrow 3\ CO_2 + 4\ H_2O + 18.85\ N_2$ (Reaction 3)

$C_4H_{10} + 6.5\ O_2 + 24.51\ N_2 \rightarrow 4\ CO_2 + 5\ H_2O + 24.51\ N_2$ (Reaction 4)

$C_5H_{12} + 8\ O_2 + 30.16\ N_2 \rightarrow 5\ CO_2 + 6\ H_2O + 30.16\ N_2$ (Reaction 5)

$(0.981\ CH_4 + 0.008\ C_2H_6 + 0.003\ C_3H_8 + 0.001\ C_4H_{10} + 0.008\ N_2) + 2.01\ O_2 + 7.58\ N_2$

$\rightarrow 1.01\ CO_2 + 2.00\ H_2O + 7.58\ N_2$ (Reaction 6)

In stoichiometric combustion, 1 mol of natural gas requires 9.59 mol of dry air.

In pre-combustion capture technologies natural gas is reformed and H_2 is combusted with air in combustion chambers. A small fraction of natural gas is combusted in an auto-thermal reformer, which is presented in chapter 5.2.1.

5.1.2 Gas Turbine

The gas turbine modeled is based on a real machine, Siemens V 94.2. The turbine is chosen because it can be converted to synthetic gas combustion (Siemens, 2011). It is assumed here that the modifications that have to be made to the gas turbine for hydrogen rich combustion will not affect the performance of the gas turbine.

The parameters of the Siemens V 94.2 gas turbine are built in the Solvo ® program in a gas turbine unit. The fuel-to-gas turbine in the Solvo ® model comes from the fuel tank unit. The fuel is defined as natural gas, but the composition of the fuel is changed to correspond to the CO_2 lean synthetic gas from the CO_2 removal unit. The CO_2 removal unit is modeled with Aspen Plus ®, which is presented in chapter 5.2.2. Figure 5.2 presents a block diagram for the gas turbine unit.

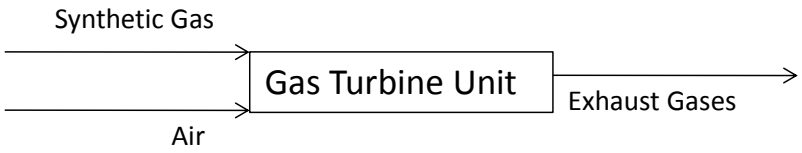


Figure 5.2*. Gas turbine unit.*

Air compressed in the gas turbine unit is conducted to the combustion chamber. In the combustion chamber, H_2 rich fuel (synthetic gas) is combusted with air and the exhaust gases are conducted to the turbine section of the gas turbine unit. There are two gas turbine units in the modeled power plant. Exhaust gases from the gas turbines are conducted to heat recovery steam generators (HRSG). These two combined gas turbine – HRSG units are identical.

5.1.3 Heat Recovery Steam Generator (HRSG)

Two HRSGs are placed after the gas turbines, one after each turbine. Hot exhaust gases from the gas turbines are conducted through the HRSG. Heat from the exhaust gases is transferred to process water, district heating water, and synthetic gas in the HRSG. A simplified block diagram of the HRSG is presented in Figure 5.3.

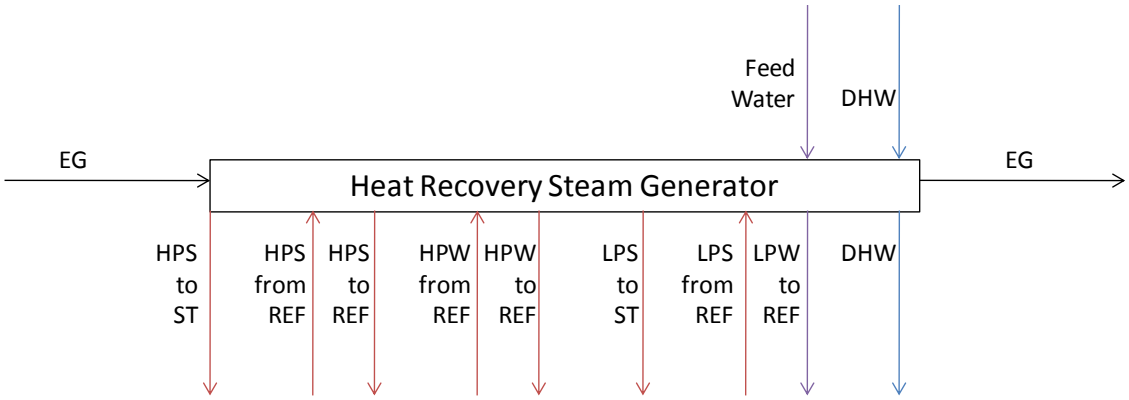


Figure 5.3. *Heat recovery steam generator.*

The key to the abbreviations in Figure 5.3 are as follows: HPS (high pressure steam), ST (steam turbine), REF (natural gas reformer), HPW (high pressure water), LPS (low pressure steam), LPW (low pressure water), DHW (district heating water) and EG (exhaust gases).

Part of process water heating takes place in the synthetic gas production section (see chapter 5.2.1). Process steam generation is highly integrated between the HRSG and synthetic gas production section, which also provides heat. The high pressure level is 90 bar, and the low pressure level 7 bar in full load. In partial load, a flexible pressure is used.

In the Solvo ® model, the heat exchangers are arranged as in Figure 5.4. Steam for the high-pressure steam superheater comes from a superheater in the reformer unit. The high-pressure superheater is modeled like the Solvo ® superheater unit. The synthetic gas preheater is modeled like the reheater unit. It only models the heat consumption of the preheater in the HRSG. The high-pressure water economizer and evaporator are

modeled like the Solvo ® heat recovery unit. The low pressure steam superheater, low pressure water evaporator, and feed water economizer are also modeled like the Solvo ® heat recovery unit. The feed water economizer operates at a low pressure level. The feed water stream is divided after the economizer. Part of it is conducted to the low pressure drum and part of it is pumped to the high pressure water economizer.

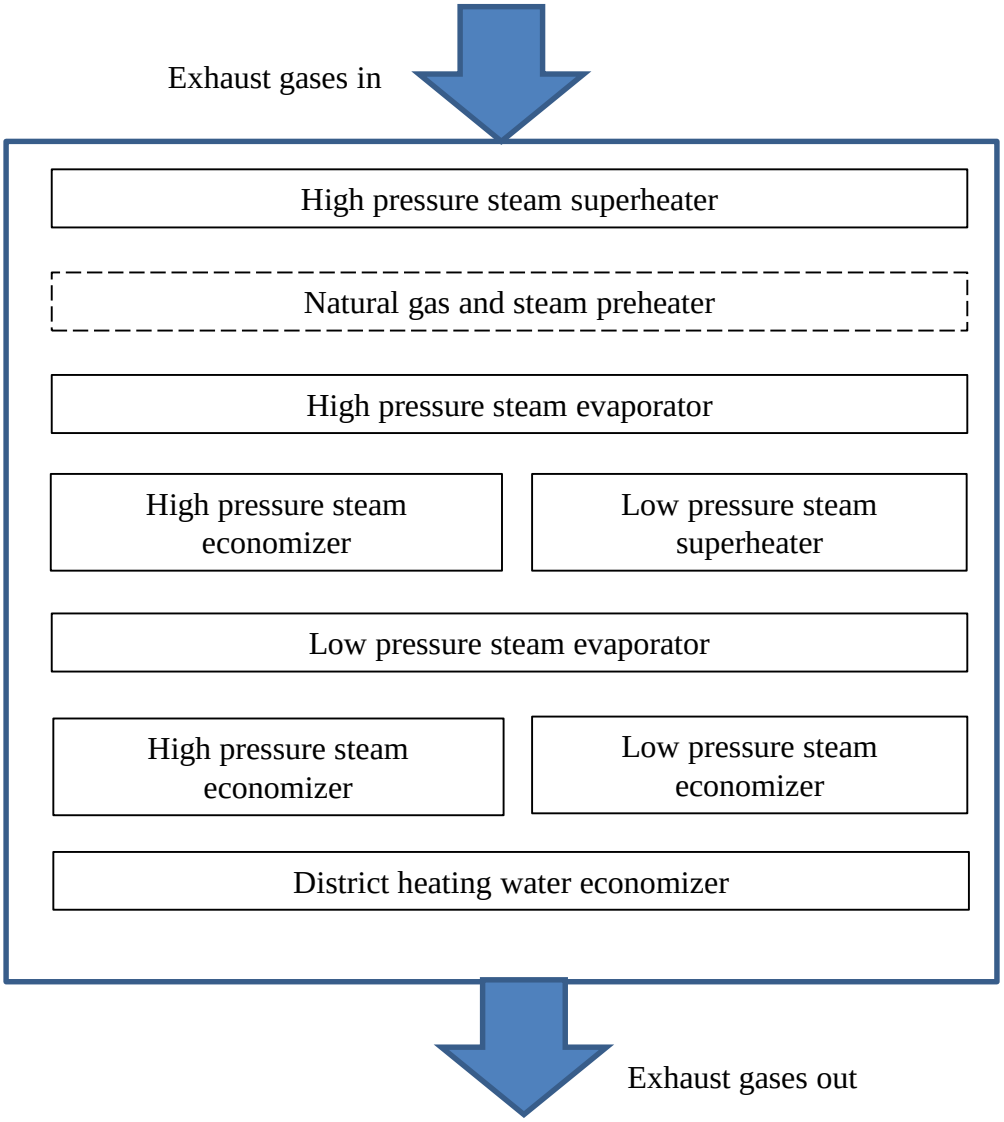


Figure 5.4. *Heat exchangers in HRSG.*

Because the stream from drum to evaporator cannot be divided in the Solvo ®, two low pressure drums are modeled: one in the HRSG and one in the synthetic gas production section. However, they are considered as one. A second low pressure steam superheater is also modeled in Solvo ® for the low pressure steam from the reformer unit. The low pressure superheaters are also considered as one. The stream integration is presented in detail in chapter 5.2.1. The process steam from the HRSG and synthetic gas production section is conducted to the steam turbine.

5.1.4 Steam Turbine

There is one steam turbine in the model. Steam from both HRSGs and from the synthetic gas production section is conducted to the one steam turbine. There are five steam extractions from the steam turbine. Medium pressure steam (MPS) from the first extraction is conducted to the reforming process (REF) in 25 bar, which is the pressure of natural gas supplied to the power plant. From the second extraction the steam is conducted to the feed water tank (FWT) at 3.5 bar. The third extraction is to the CO_2 separation unit (ABS) at 0.63 bar. From the last two extractions the steam is conducted to the district heating water heat exchangers (DH). The remainder of the steam expands at the end of the steam turbine to a pressure of 0.02 bar and is conducted to a condenser (COND). The block diagram for the steam turbine unit, the condenser and the feed water tank is presented in Figure 5.5.

In Solvo ® the steam turbine consists of 7 separate steam turbine units linked to each other with a shaft. High pressure steam (HPS) is conducted to the first turbine from which the first extraction is taken. Low pressure steam (LPS) is conducted to the third turbine unit. In the first and second steam turbines the isentropic efficiency is 0.90 and in the remaining steam turbines 0.85.

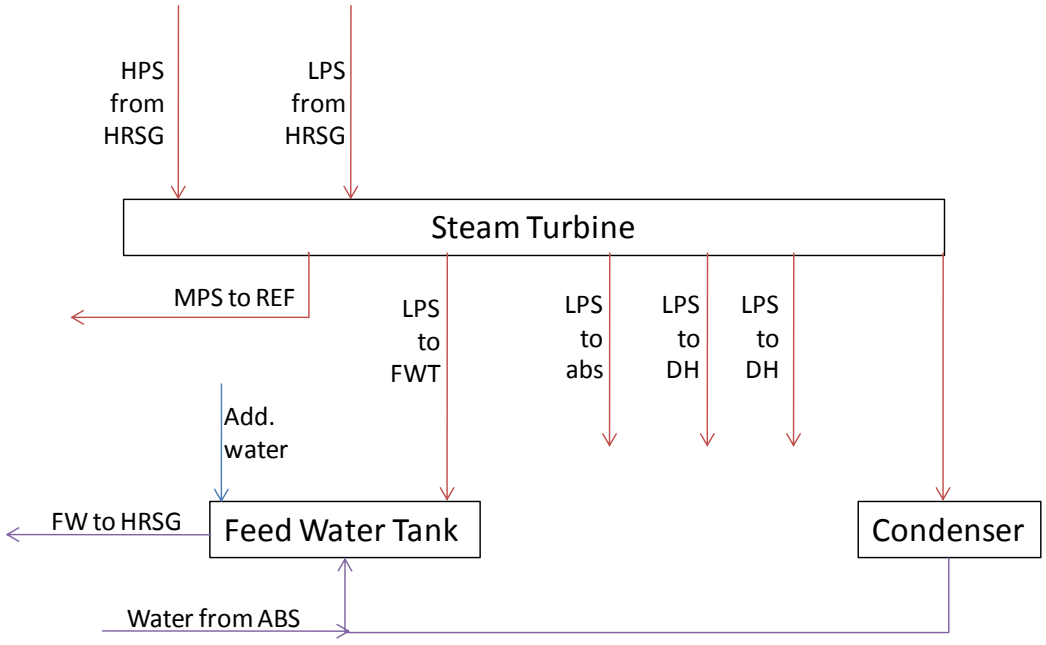


Figure 5.5. *Steam turbine, condenser and feed water tank.*

5.1.5 District Heating

The power plant has two heat exchangers for district heating water. The district heat consumption is the main parameter influencing the plant size. The ccold district heating

water stream is divided into two streams. One stream is conducted to the HRSG and one to the low temperature heat exchanger. After the low temperature heat exchanger, the streams are combined and conducted to the high temperature heat exchanger. The heating power required by the district heating is modeled with a district heating sink.

The heat exchangers are sized with district heating water entering the first heat exchanger at a temperature of 45°C and the second at 75°C. The temperature difference to steam condensing in both district heating water heat exchangers is 4°C. Hot district heating water is 83°C and returning cold district heating water 45°C. The district heating unit is presented in Figure 5.6.

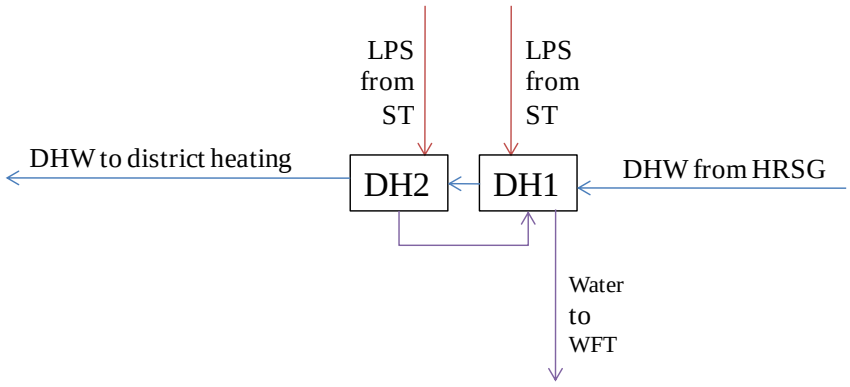


Figure 5.6. *District heating.*

5.2 CO_2 Capture

Pre-combustion technology is chosen for modeling in the thesis. The reasons behind the choice are presented in chapter 3.5. The main components of CO_2 capture technology modeled are the auto thermal reformer (ATR) and the absorption system. The ATR generates synthetic gas from which CO_2 is removed in the absorption system. After absorption, synthetic gas is conducted to the gas turbine.

5.2.1 Synthetic gas production section

The integration between the synthetic gas production section and the HRSG is an important factor influencing the total efficiency of the power plant. Bolland and Nord (2011) have compared different system integrations. The system integration that they found the best is the basis for the model in this thesis.

The places of the heat exchangers are almost the same as in the Bolland and Nord (2011) article. Some exceptions are made because of the district heating section, which Bolland and Nord (2011) do not have in their model. The process values are different because the gas turbine selected in the thesis differs from that in Bolland and Nord

(2011), and because of the influence of the district heating system on the process. A simplified block diagram is presented in Figure 5.7. The heat exchangers are presented in detail in Figure 5.8.

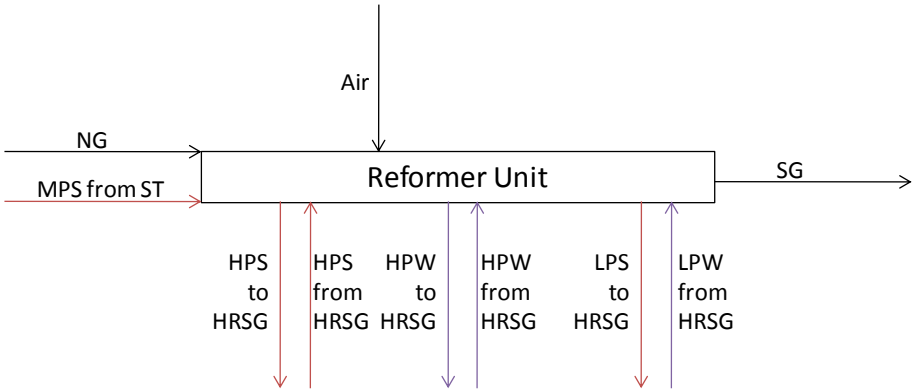


Figure 5.7. *Reformer unit.*

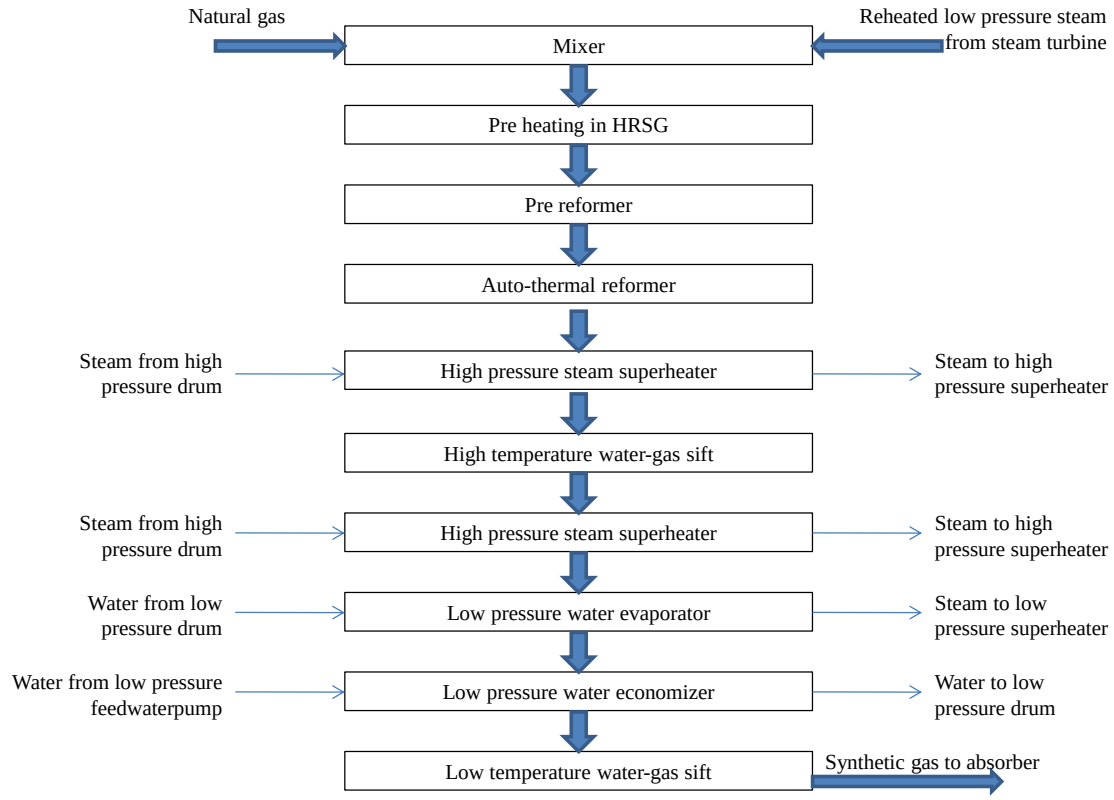


Figure 5.8. *Reformer unit in detail.*

In the reforming process low pressure steam and natural gas are first mixed. After mixing, in the pre-reformer heavier hydrocarbons are reformed (reactions (8), (9) and (10)). After pre-reforming the gas is to the auto thermal reformer. Auto thermal reforming is partial oxidation followed by thermal and catalytic steam reforming. The

values used in the reforming process are based on the Corradetti and Desideri (2005) article.

Chemical reactions in the reforming process:

$$CH_4 + H_2O \leftrightarrow CO + 3H_2 \quad \text{(Reaction 7)}$$

$$C_2H_6 + 2\ H_2O \rightarrow 2\ CO + 5H_2 \quad \text{(Reaction 8)}$$

$$C_3H_8 + 3\ H_2O \rightarrow 3\ CO + 7H_2 \quad \text{(Reaction 9)}$$

$$C_4H_{10} + 4H_2O \rightarrow 4CO + 9H_2 \quad \text{(Reaction 10)}$$

$$CO + H_2O \leftrightarrow CO_2 + H_2 \quad \text{(Reaction 11)}$$

Not all methane entering the ATR is reformed because part of it functions as fuel supplying heat for the endothermic reaction. The endothermic reaction requires energy. The combustion reaction occurs in the upper part of the ATR and can be simplified by reaction (1) (chapter 5.1.1). The endothermic methane reforming reaction (7) occurs in the lower part of the ATR. Air is used as an oxidizer in the ATR, thus the gas leaving the ATR contains a large amount of nitrogen. The methane steam reforming reaction uses the heat from the oxidation reaction, thus the temperature in the ATR does not rise as high as it would if only the oxidation reaction occurred.

After the ATR the gas is conducted to the first heat transfer in the reforming process, which is a high-pressure steam superheater. In the superheater high-pressure steam from the HRSG is heated and conducted to the superheater in the HRSG. After the first high-pressure steam superheater the gas is conducted to a high-temperature shift reactor (HTS) in which a water-gas shift reaction (11) occurs.

After the HTS the gas is conducted to the second high pressure steam superheater, which operates in the same way as the first. After the second high-pressure steam superheater the gas is conducted to the low pressure water evaporator, where water that comes from the low-pressure drum evaporates. Steam leaving the evaporator is conducted to the low-pressure superheater in the HRSG. The last heat exchanger in the reformer unit is the low-pressure water economizer. The water for the economizer comes from the feedwater pump and is conducted to the low-pressure drum.

The energy balances of the components are modeled in MS Excel as follows:

$$Q+\sum(N_iH_{mt,i})=\sum(N_oH_{mt,o}) \quad \text{(Equation 6)}$$

where Q is the reaction enthalpy in the reference temperature, N is the amount of the reaction component in moles, and H_{mt} is the enthalpy of the component at a certain temperature.

The reforming reactors are assumed to be adiabatic. Because the reactions (7) and (11) are reversible, the compositions in the selected temperatures and pressures are calculated with the equilibrium constant K_p as follows:

$$K_{p,(7)} = \frac{(p_{CO}/p^0)^1 (p_{H_2}/p^0)^3}{(p_{CH_4}/p^0)^1 (p_{H_2O}/p^0)^1} \quad \text{(Equation 7)}$$

$$K_{p,(11)} = \frac{(p_{CO_2}/p^0)^1 (p_{H_2}/p^0)^1}{(p_{CO}/p^0)^1 (p_{H_2O}/p^0)^1} \quad \text{(Equation 8)}$$

where $K_{p,(i)}$ is the equilibrium constant of equation i, p_i is the partial pressure of component i, and p^0 is normal pressure (Oksanen, 2010). The reformer is summarized in Table 5.2.

Table 5.2. Reformer.

Component	**Description**	**Reactions**
Mixer	Mixes the natural gas and HP steam (from the HRSG)	
Pre-reformer	Reforms the heavy carbon oxides	$C_2H_6 + 2H_2O \rightarrow 2CO + 5H_2$ $C_3H_8 + 3H_2O \rightarrow 3CO + 7H_2$ $C_4H_{10} + 4H_2O \rightarrow 4CO + 9H_2$
Auto thermal reformer (ATR)	Burns a fraction of methane and reforms the remainder	$CH_4 + 1{,}5O_2 \leftrightarrow CO + 2H_2O$ $CH_4 + H_2O \leftrightarrow CO + 3H_2$
Heat exchangers 1, 2 and 3	Reduces synthetic gas temperature and heats steam	
High temperature shift (HTS)	Reforms CO in synthetic gas to CO_2	$CO + H_2O \leftrightarrow CO_2 + H_2$
Heat exchangers 4 and 5	Reduces synthetic gas temperature and creates steam or heats water	
Low temperature shift (LTS)	Reforms CO in synthetic gas to CO_2 (ready to absorber)	$CO + H_2O \leftrightarrow CO_2 + H_2$

5.2.2 CO_2 removal and compression

The main components of the CO_2 removal and compression unit are the absorber tower, the stripper tower, and the compressors. They are modeled using the Aspen Plus ®. The process values in CO_2 removal are chosen as in the literature (Corradetti and Desideri, 2005; NETL 2010; Kvamsdal et al, 2006; Bolland and Nord, 2011). The absorption stripper model structure is based on the article by Corradetti and Desideri (2005) and a report by NETL (2002). The equilibrium diagram for CO_2 removal and compression unit is presented in Figure 5.9. The absorption stripper process is presented in detail in Figure 5.10.

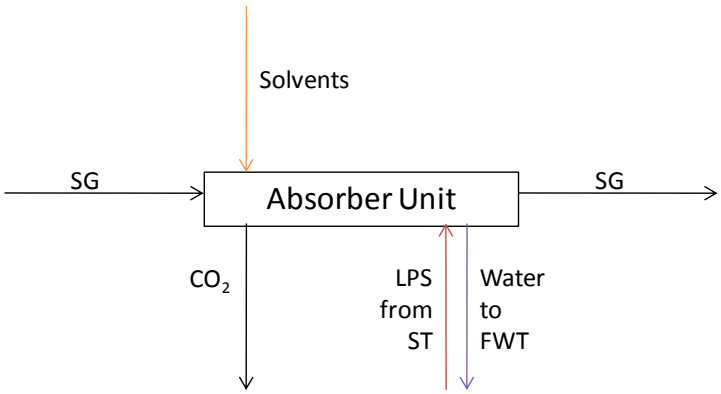


Figure 5.9. *CO_2 removal and compression unit.*

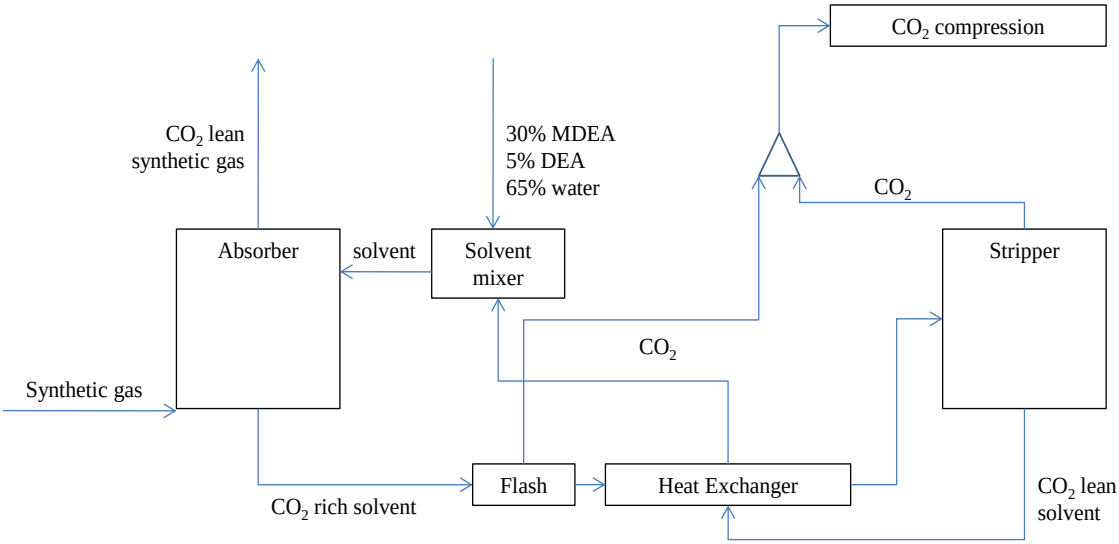


Figure 5.10. *Absorption stripper process flow.*

CO_2 removal is accomplished by the MDEA and DEA absorption process. The MDEA and DEA process is chosen because only A small amount of steam is required for regeneration of the solvent in the stripper. The solvent used is a mix of MDEA, DEA

and water. MDEA is chosen because of its low energy requirements, high capacity, and stability in acid gas removal. MDEA is also less corrosive than other amines, thus cheaper building material can be used. The disadvantage in using MDEA is its low rate of reaction with CO_2. The addition of DEA increases the rate of CO_2 absorption significantly without diminishing MDEA's many advantages. (Kohl and Nielsen, 1997)

If it is assumed that equilibrium is attained in both the absorption and stripping steps and isothermal conditions are maintained, the maximum net capacity of the CO_2 removal unit is the difference between equilibrium concentrations at the absorption and stripping partial pressures. Equilibrium reactions are presented below. Carbamate formation does not happen to MDEA. (Kohl and Nielsen, 1997)

Equilibrium reactions:

Ionization of water:

$H_2O = H^+ + OH^-$ (Reaction 12)

Hydrolysis and ionization of dissolved CO_2:

$CO_2 + H_2O = HCO_3^- + H^+$ (Reaction 13)

Protonation of alkanolamine:

$MDEA + H^+ = MDEA^+$ (Reaction 14)

$DEA + H^+ = DEA^+$ (Reaction 15)

Carbamate formation:

$DEA + HCO_3^- = DEACOO^- + H^+$ (Reaction 16)

The amines and water are mixed in a mixer. The lean solvent, added MDEA, DEA and water are conducted to the mixer. The solvent from the mixer is fed to the absorber column from the upper part of the column. Synthetic gas is fed to the absorber tower from the lower part of the column. Water is removed from the synthetic gas before conducting it to the absorber column. The CO_2-rich solvent is removed from the bottom of the absorber column. Cleaned synthetic gas is removed from the top of the absorber column.

CO_2-rich solvent is then conducted to a flash drum, where the pressure is lowered. The reduction in the pressure releases part of the CO_2, which is conducted to compression.

The remainder of the CO_2 is desorbed form the solvent in the stripper column. The stripping agent is the vapor of the solvent itself, which is produced in a reboiler. The steam, that evaporates the solvent in the reboiler, is extracted from the low pressure end in the steam turbine.

From the stripper column, the lean solvent is conducted back to the mixer. Because of the temperature difference between the lean solvent and the rich solvent, a heat exchanger is placed after the lean solvent pump for lean solvent and before the stripper for rich solvent. CO_2 leaving the top of the stripper column is compressed and liquefied to 7 bar and -50°C. The compressor unit available in the Aspen Plus ® could not liquefy CO_2. The liquefaction was done in a flash drum. The thermal power of the flash drum was then converted into the work that should be done. The conversion was done by using the coefficient of performance (COP) value 1.5 (Ramgen Power Systems, 2009).

5.3 Reference Plant

The results are compared to a conventional CCGT CHP without CO_2 capture. The reference plant is based on the same two gas turbines as the case with CO_2 capture. It is modeled with the Solvo ®. The heat production of the reference plant is fixed to be roughly the same as in the cases with CO_2 capture. The heat production of the CCGT CHP without CO_2 capture would otherwise be higher. The reduction of the heat production results in a slightly higher power-to-heat ratio. Thus, a condensing unit of steam turbine is needed for the steam to expand to lower pressure.

It is clear that all the effects of CO_2 capture technology on the the CCGT CHP are due to the changes in the power plant. The effects depend on how the added technology is integrated into the CCGT CHP. In the case of the thesis, the rate of integration is high, especially between the reformer and the HRSG. The main differences between the conventional CCGT CHP and the CCGT CHP with pre-combustion CO_2 capture technology can be seen in Figures 5.11 and 5.12.

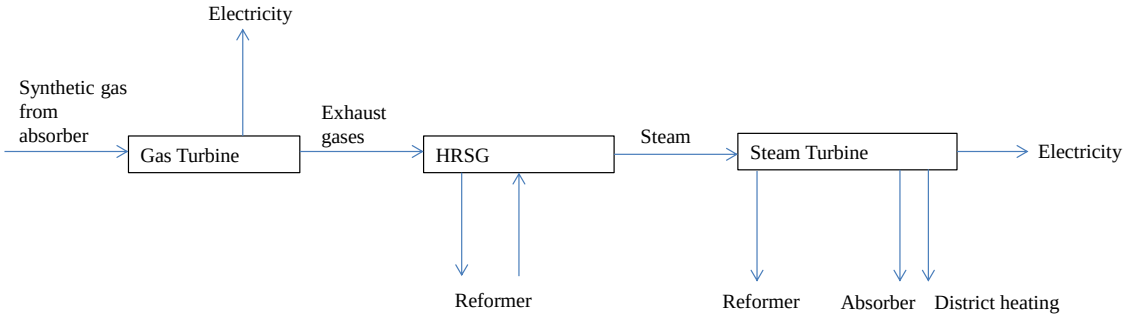


Figure 5.11. *CCGT CHP with CO_2 capture*

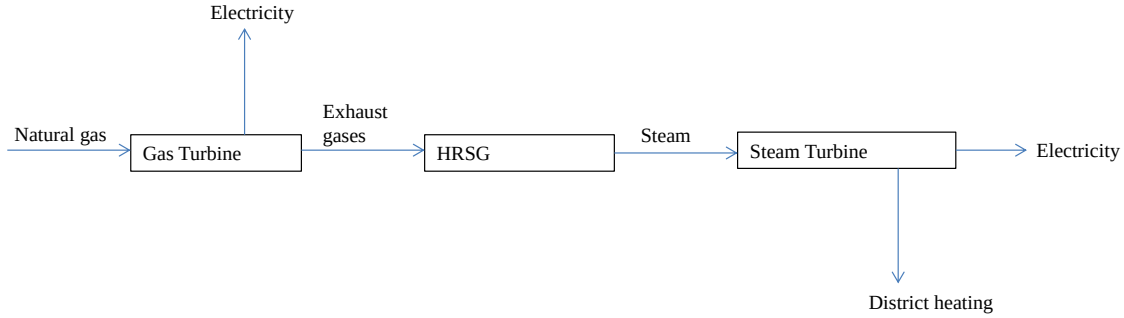


Figure 5.12. *CCGT CHP without CO_2 capture.*

As the figures above show, the main differences are the fuel entering the gas turbine, integration between HRSG and the reformer, extraction from the steam turbine to the reformer and to the absorber. The figures are simplified and only the main streams are shown.

6 COST ASSUMPTIONS

In this chapter the cost assumption of the power plant are presented. First, the operating hours of the power plant are calculated. Then the total investment cost and the prices of consumables and products are estimated. Taxes are included in the prices, except value added tax (VAT).

6.1 Operating hours

The size of the power plant is approximated from the heat demand of the area where the power plant is built. It is assumed that all the electricity that is produced along with the heat can be sold on the power market. The size of the power plant is a major assumption affecting the total costs of the plant.

The heat production in 2010 at the power plant site on which the power plant modeled in this thesis is planned to be located is presented in Figure 6.1. The data, on the basis of which the figure is drawn, is not completely reliable. Many errors, e.g. values below zero, were found when the data was cleaned. The heat demand duration curve in the area where the power plant is located is based on data from two years, and is presented in Figure 6.2. The red area in the Figure 6.2 illustrates the main demand which the power plant is planned to meet. Figure 6.1 is drawn on the basis of raw data and Figure 6.2 on the basis of cleaned data. (Fortum, 2011)

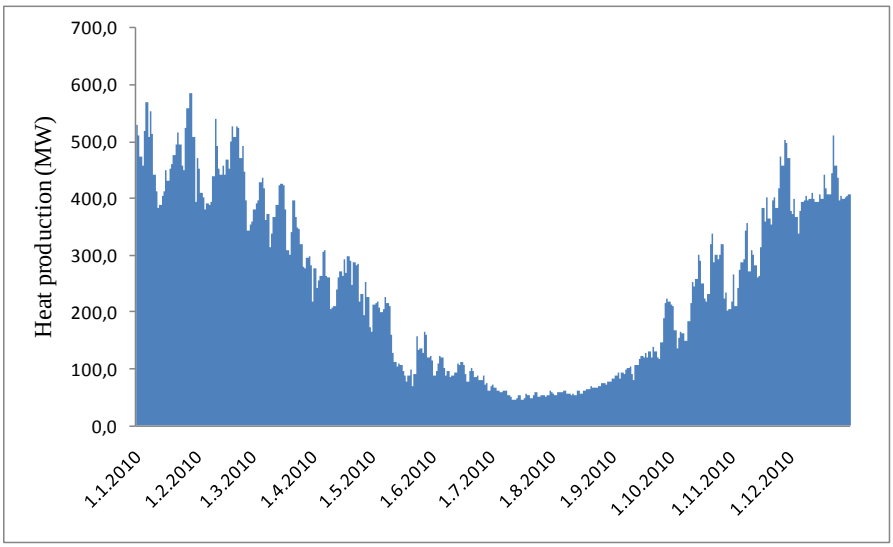


Figure 6.1. *Heat production. (Based on Fortum, 2011)*

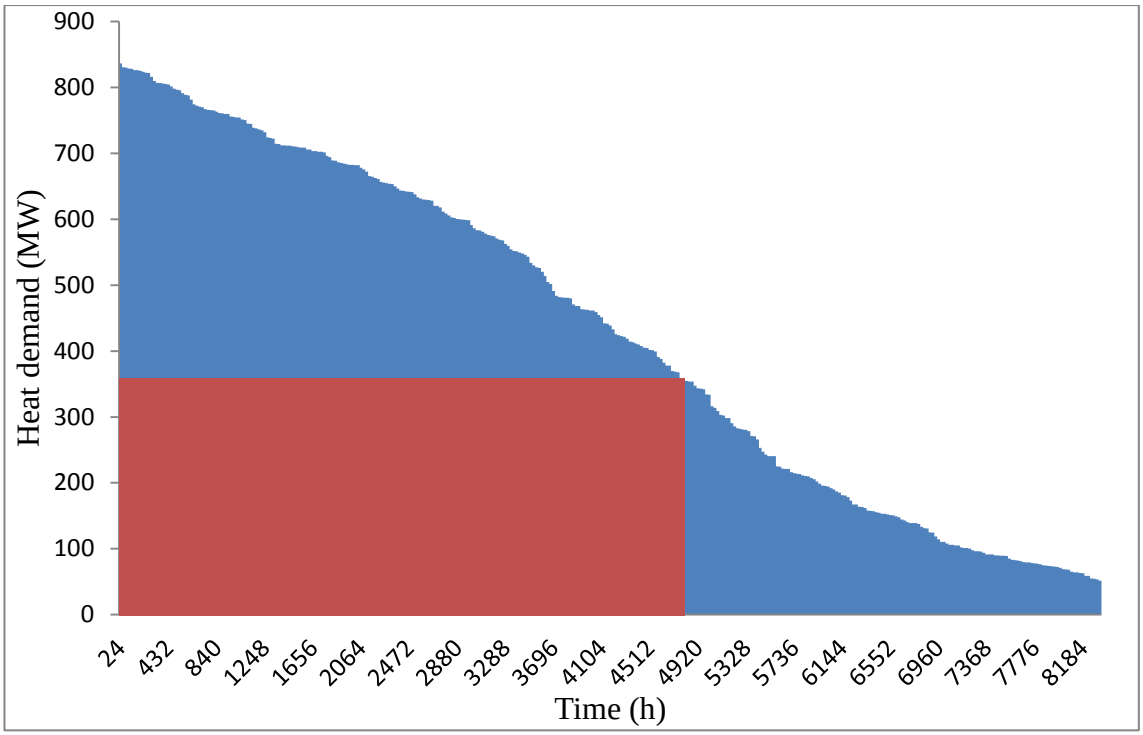


Figure 6.2. *Heat demand duration curve. (Based on Fortum, 2011)*

The peak load can be defined as the power demand, the duration of which is less than 500 hours. The base load demand duration is at least 6,500 hours. (VTT, 2004) As seen in Figure 6.2, the power plant designed here meets neither peak nor base load demand. Thus, it is an intermediate load power plant. The power plant operates 4,776 hours per year at full load, which are the peak operation hours.

It is assumed that the heat demand will not change dramatically in the future. This assumption has to be made because the startup year for the power plant is 2020. The startup year has been chosen to be as far in the future because the technology modeled here is most likely to be in use then (Energy Policy for Europe, 2007).

6.2 Total Investment Cost

The costs of the power plant are mainly evaluated based on the literature. The investment costs are presented in Table 6.1. The cost information found in the literature is scaled to the case in the thesis based on reference scaling percentages in the VTT publication (2004). Doubling the size of the power plant increases the investment cost by 60% and decreases unit cost 20% (VTT, 2004). As mentioned in chapter 4, the accuracy of the calculation method is between -30% and +50%. Even though reliable cost information was found, it must be emphasized that the assumptions here are not made directly from the power plant data. The assumptions are made based on the best available information.

Table 6.1. Investment cost breakdown. (Foster Wheeler, 2010; Raiko, 2011)

TOTAL INVESTMENT COST	**M€**
Power plant (2 GT+HRSG, ST, DH)	303
CO_2 removal, compression and liquefaction	156
Reformer	508
Balance of plant	168
TOTAL	1,135

The investment cost of a Combined Cycle Gas Turbine (CCGT), based on the same gas turbines without carbon capture, for power and heat production is expected to be €270 million (Raiko, 2011). The power plant unit cost with pre-combustion carbon capture is estimated to be 1.12 times the conventional power plant cost (Foster Wheeler, 2011). This is mainly due to the modifications that have to be made to the gas turbine for hydrogen combustion.

The reformer investment cost is high compared to the other components. However, it can be assumed that the reformer technology in power plant use is in an early stage in the learning curve. The learning curve is based on a finding that the time needed to produce a product shortens the more the product is produced (Haverila et al, 2005). It can be used when setting the price for the product. For an example of the effect, the impact of the learning curve on electricity production costs in wind power is presented in Figure 6.3. Thus, it can be assumed that the cost of the reformer will decrease in the future.

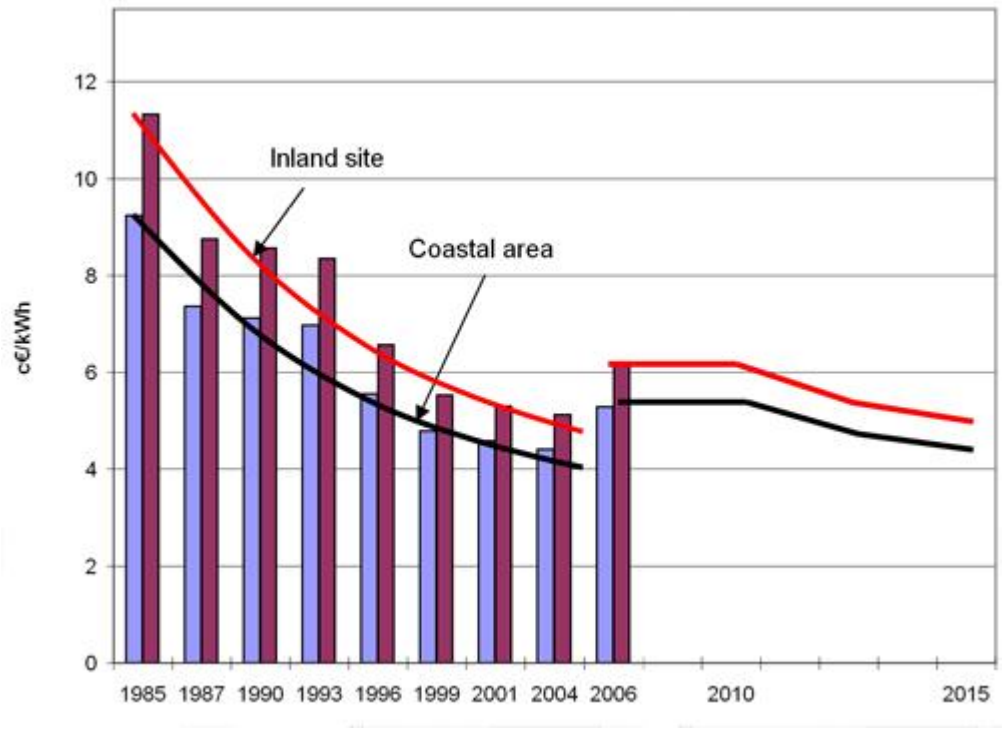


Figure 6.3. *Wind power learning curve. (Wind Energy, 2011)*

In calculations, an interest rate of 5% is used. The interest rate is chosen because it is the usual interest rate used in Finland when comparing power sector investments (VTT, 2004).

6.3 Operating Cost and Revenue

Operating costs are divided into fixed and variable costs. Variable costs are estimated based on the price forecast for natural gas, solvents, raw water and emission allowance. The prices of the consumables are presented in Table 6.2. The prices of solvents are based on the Foster Wheeler report (2010) and the ICIS report (2010). The prices of transportation and storage of CO_2 are based on the VTT report (2011).

The avarage price of natural gas in 2010 for a user similar to the power plant modeled in the thesis was €31 / MWh (SVT, 2011). Kangas (2007) has forecast the price of natural gas to be €35 / MWh in 2020 in Europe. The value of €31 / MWh has been chosen. The price of natural gas depends, among other things, on the price of haevy fuel oil. Thus, it is challenging to forecast future prices, and it is more reliable to use the current prices.

Taxes on natural gas are now €9.024 / MWh. They include energy content tax, carbon dioxide tax and maintenance support performance fee. The energy content tax is now €3

/MWh, but it is planned to be rised to €7.70 / MWh in 2015. However, the situation is going to be evaluated before the later tax increase. (Tullihallitus, 2011)

Energy taxes must be paid on the fuel in heat production, but not on electricity production. The amount of natural gas on which taxes must be paid is the amount of heat produced multiplied by 0.9. (Tullihallitus, 2011)

Table 6.2. Variable operating cost break down.

Consumables	**Price**
Natural gas	€31 / MWh (taxes excluded) €45 / MWh (taxes included)
MDEA	€3,830 / tonne
DEA	€1,000 / tonne
Raw water	€0.102 / 1,000 l
CO_2 transport	€15 / CO_2-tonne
CO_2 storage	€11 / CO_2-tonne

As seen in the table above, emission allowances are not handled as variable costs here. In this approach, emission allowances are regarded as consumables which have to be bought from the market based on the polluting rate. It is deemed that CO_2 cannot be "produced" without a CO_2 allowance. In other words, the CO_2 allowance is the "raw material" for CO_2 emissions into the atmosphere.

However, it is assumed here that emission allowances are given to a company free of charge. Thus, because they do not need all of them, they can sell them. In contrast to the alternative approach presented above, here the emission allowances are "produced" by capturing CO_2. The cost of CO_2 capture should be covered by selling emission allowances. The differences in approaches is shown in Figure 6.4.

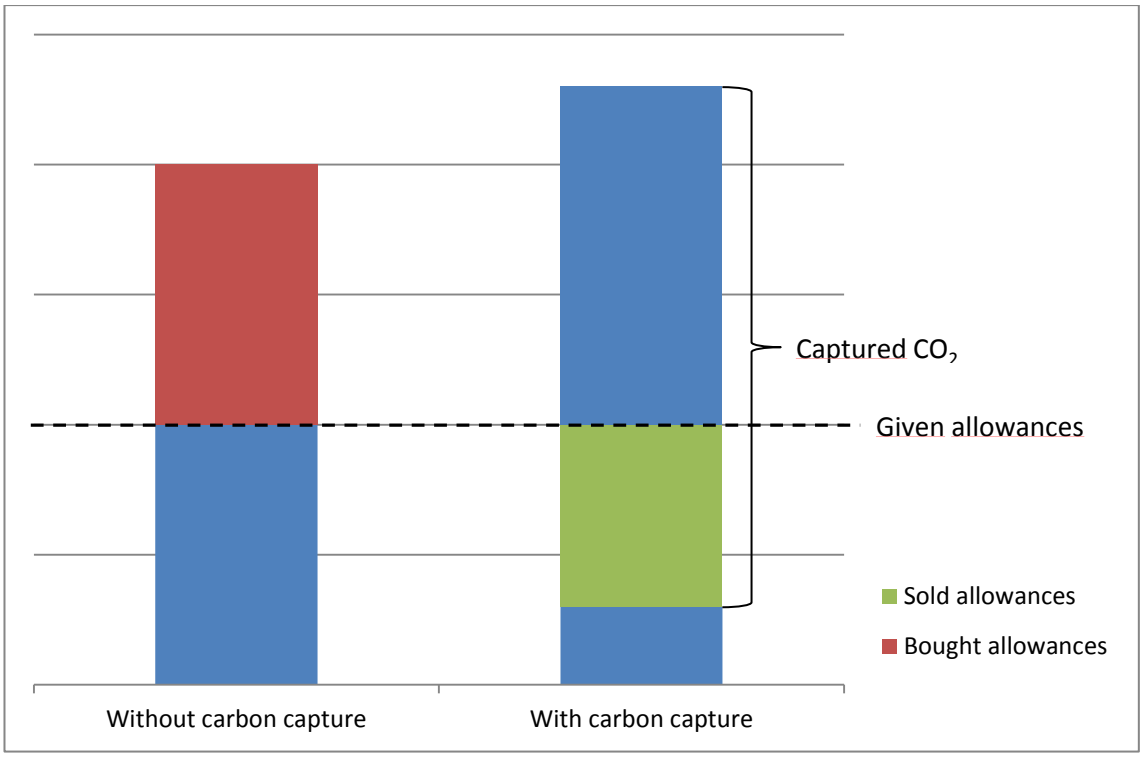


Figure 6.4. *Approaches to emission allowance calculations.*

By choosing the latter approach, the results do not have to be compared to the CCGT CHP without CO_2 capture. In the first approach, the feasibility of CO_2 capture would have been evaluated by comparing the costs of CCGT CHP with CO_2 capture to CCGT CHP without CO_2 capture. In the latter approach, it is evaluated comparing the cost of CO_2 capture and the revenue from selling the emission allowances. The assumption that all the emission allowances are granted free of charge for the CCGT CHP with CO_2 capture is supported by the European Commission (2010) decision to support the CCS project with emission allowances through the NER300 instrument.

Fixed operating costs are labor, maintenance and overhead costs. It is assumed that the number of personnel required to operate the power plant is five for each of four shifts. The labor costs in the electricity, heat, and gas sector in 2008 were €56,500 per person (SVT, 2008).

Overhead costs are assumed to be 30% of the operating labor costs. The fixed costs are presented in Table 6.3. Maintenance costs are estimated as 3% of the total investment costs. (Foster Wheeler, 2010)

Table 6.3. Fixed operating costs.

Labor	€56,500 / employee
Maintenance	3% of total investment costs
Overhead changes	30% of labor costs

Revenues are estimated based on the price forecast for electricity, heat and emission allowances. The prices are shown in Table 6.4. The annual avarage of the Nord Pool spot electricity price in 2010 in Finland was €56.64 / MWh (Nord Pool, 2011). The price of electricity in the startup year of the power plant is forecast to be €100 / MWh by Koskelainen (2010), and €47 / MWh by Pöyry Oy (Laatikainen, 2011). Because the natural gas price was chosen to be the avarage price in 2010, the electricity price, too, has been chosen to be the same as in 2010.

From 1 January 2011 to 1 August 2011 the price of the emission allowance forward to the year 2015 has been between €15–25 / CO_2-tonne (EEX, 2011). Koskelainen (2010) forecast the emission allowance price to be €40 / CO_2-tonne in 2020. In a bill (HE 152/2010 vp) on electricity production subsidy for renewable fuels, the emission allowance price was estimated to be €20 / CO_2-tonne in 2020. Reuters reported that Barcap Capital lowered the average price forecast for the period 2013 to 2020 to €30 / CO_2-tonne from €40 / CO_2-tonne. Reuters (2010) forecast the emission allowance price to be €29.90 / CO_2-tonne. Based on these forecasts, the emission allowance price €30 / CO_2-tonne has been chosen because it can be expected that the price of the emission allowance will rise when the number of emission allowances on the market is reduced (European Commission, 2010).

The price of district heating is based on the district heating prices in the area where the power plant is planned to be located. The prices of district heating in Finland are available from the internet pages of Energiateollisuus (Energiateollisuus, 2011).

Table 6.4. Prices of electricity, heat, and emission allowance.

	Prices
Electricity	€57 / MWh
Heat	€55 / MWh
Emission allowance	€30 / CO_2-tonne

The total cash flow is presented in Figure 6.5. All prices are expected to increase at an annual inflation rate of 2.5%.

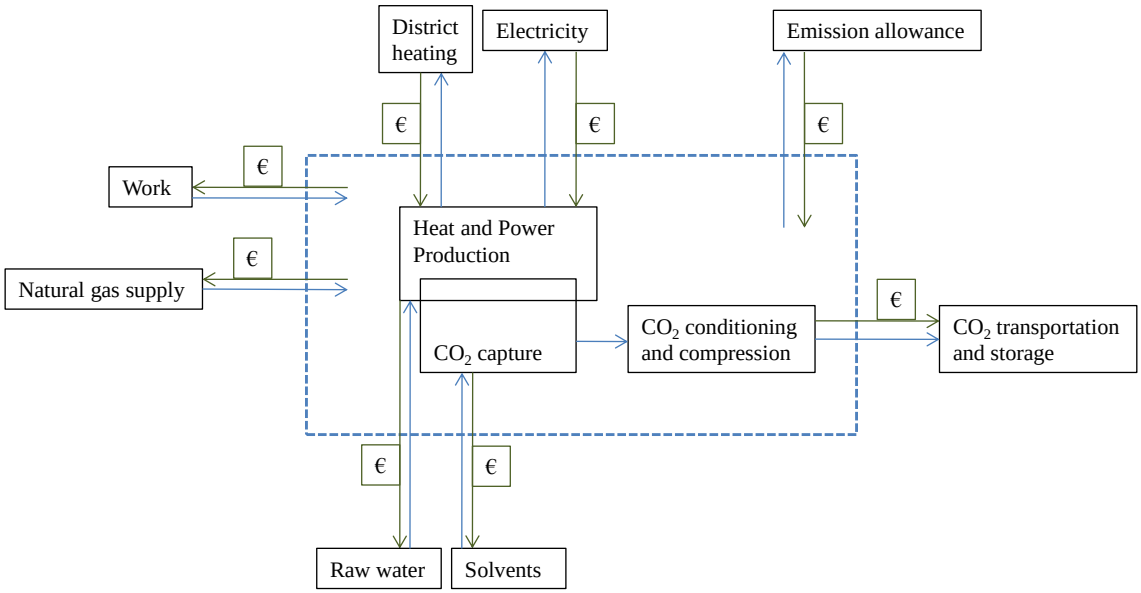


***Figure 6.5**. Cash flow.*

7 PROCESS MODEL RESULTS AND DISCUSSION

This chapter presents the results of the process modeling. The CCS case is compared to the reference case.

The operation of the power plant was modeled with three different CO_2 capture rates (97%, 90%, and 80%). Also four different loads (100%, 90%, 80%, and 70%) were modeled. However, the effects of the partial loads could not be reliably simulated because the factors that should be fixed could not be in the Aspen and Excel models. Thus, the partial load cases need further attention, and the results of the simulations are not reported here.

As mentioned in chapter 1, the effects on following parameters were studied:

- energy efficiency
- power-to-heat ratio
- fuel input
- emissions

Simulation with the model was challenging, as it is composed of four separate models. The large number of integrations between the models made it difficult to get the whole model to converge.

7.1 Process Modeling

The summary of the plant performance at full load and with a capture rate of 90% is presented in Table 7.1. The results of the reference plant are also included in the table.

Table 7.1. Plant performance.

PLANT THERMAL INPUT	**CCGT CHP with CO_2 capture**	**CCGT CHP without CO_2 capture**
Thermal Energy of Natural Gas	1,003 MW	841 MW
PLANT ELECTRICAL OUTPUT		
Electric Power Output at Generator		
Gas Turbine	294 MW	273 MW
Steam Turbine	152 MW	130 MW
Total	446 MW	403 MW
Gross Electrical Efficiency	0.44	0.48
Auxiliary Electrical Consumption	21 MW	1,7 MW
Net Electrical Output	425 MW	401 MW
Net Electrical Efficiency	0.42	0.48
PLANT THERMAL OUTPUT		
District Heating	353MW	351 MW
Absorber Unit Heat Consumption	96 MW	-
OVERALL PLANT EFFICIENCY		
	0.78	0.89
POWER TO HEAT RATIO		
	1.20	1.14

7.1.1 Efficiency

As expected, the efficiency of the power plant is lower than the efficiency of a CCGT without CO_2 capture. The efficiency of a CCGT CHP without CO_2 capture can be up to 91%. The drop in this case is 11% units.

In a previous study, the drop has been 21% units (Foster Wheeler, 2010). The difference might be due to auxiliary electrical consumption that is much higher in the Foster Wheeler (2010) study. This raises a question if all the auxiliaries are taken into account in this case. Another possible reason is different process steam and water integration between the HRSG unit and the reformer unit. In addition, it was assumed here that there were no losses in the integration. One possible reason is different decisions made in the tradeoff between CO_2 removal heat consumption and the solvent leakage situation. Also, a different CO_2 condition at the calculation limit might be a reason for the difference in the efficiency. If CO_2 is to be transported in a pipeline, it is pressurized to a higher pressure than in the case in the thesis in which the CO_2 is liquefied for ship transportation. However, none of these reasons are likely to cause the difference alone. Thus, it can be concluded that the difference is a combination of more than a one cause.

In previous studies the efficiency drop for CCGT power production without heat production has been 5–8% units (Kvamsdal & al. 2007; NETL, 2010). This means a 9%–15% drop in efficiency. Here, the total drop in total plant efficiency is 11%. The drop in electrical efficiency is 6% units, which is 13% from the net electrical efficiency of the CCGT CHP without CO_2 capture. This falls into the same range as in the previous studies of CO_2 capture in a CCGT without heat production. It was expected that the energy penalty for electricity production would be lower in CHP production than in condensing power production because in CHP the energy penalty caused by the CO_2 capture is divided between power and heat production. However, the net electrical efficiency is lower in CHP production than in CCGT power production. Thus, the decrease of 1% unit is less in percentages in the condensing power case than in the CHP case.

In the previous study the efficiency drop for coal-fired CHP was only 5% units. However, the drop in electrical efficiency is 12% units. The lower total efficiency is due to the increase in heat efficiency by 9% units. (Gode and Hagberg, 2008)

The CCGT CHP has better efficiency than the coal CHP. However, the CCGT CHP with CO_2 capture case in the thesis has lower efficiency than the Gode and Hagberg (2008) coal CCS case in which it was 0.86. On the other hand, in the Gode and Hagberg (2008) coal CCS case, the drop in electricity efficiency is greater than in the CO_2 capture case in the thesis. Because the heat load is the factor that states the size of the CHP plant, the CCGT CHP would produce significantly more electricity than coal-fired

CHP. The reasons behind the difference cannot be further examined because there was not enough information about the coal case available.

7.1.2 Power-to-Heat Ratio

The power-to-heat ratio for a modern CCGT CHP is higher than 1.00. For example, the power-to-heat ratio of the Suomenoja CCGT CHP is 1.09 (Fortum, 2010). In the reference case, the power-to-heat ratio is 1.14. The relatively high power-to-heat ratio in the reference case is due to the added condensing unit of the steam turbine, where part of the steam is not extracted to district heating heat exchangers, thus it expands to the condenser pressure, producing more electricity. This is done because the reference plant is fixed to produce roughly the same amount of heat for being comparable to the CCS case.

Another possible way to compare the results between the reference plant and the CCGT CHP with CO_2 capture is not to fix the heat production. In that case, the reference plant would have a higher heat output, and thus have lower peak operation hours, as seen in Figure 6.2, chapter 6.1.

In the CCGT CHP with CO_2 capture, the power-to-heat ratio is 1.2. This is higher than in the reference case. This indicates that the energy penalty of CO_2 capture unit is higher for heat than for electricity. This can be explained by the large steam extraction from the steam turbine to the absorber in the CO_2 removal unit. The extraction is carried out at around the same pressures as the extractions to the district heating heat exchangers. This reduces the steam mass flow to the district heating heat exchangers, but the steam expands to the same pressure as in these extractions. This can be seen in Figure 7.1, where the energy flows to the CCGT CHP with and without CO_2 capture are presented.

The heat extraction to the absorber is larger than the heat consumption of the absorber because not all the heat can be exchanged in the reboiler and in the absorber. The extraction from the steam turbine to the reformer in the CO_2 removal unit does not affect the power-to-heat ratio as much because it is taken from a higher pressure and thus affects both heat and electricity production.

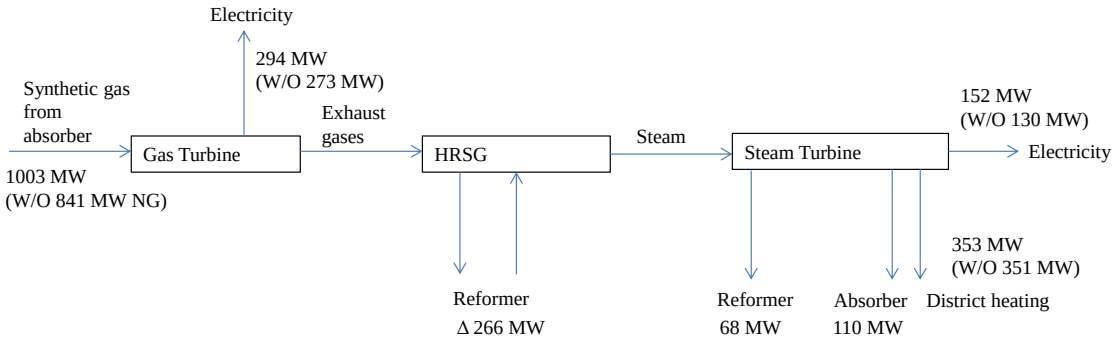


Figure 7.1. *The energy flows to the CCGT CHP with and without CO_2 capture.*

The CCGT CHP with CO_2 capture produces more electricity in the steam turbine because the mass flow in the steam turbine is larger than in the reference case. The mass flow is larger because steam is produced in both the HRSG and the reformer. In the reference case, steam is only produced in the HRSG.

7.1.3 CO_2 Emissions

Annual CO_2 emissions are 91 kt in the case of the 90% capture rate. Total CO_2 emissions from the energy industry in Finland were 25 Mt in 2009 (SVT, 2011), which does not include the emissions from industrial energy production. The reference plant without CO_2 capture produces 802 kt of CO_2 annually. The avoided CO_2 emissions in this case would be 802–91 kt = 711 kt. This is presented in Figure 7.2.

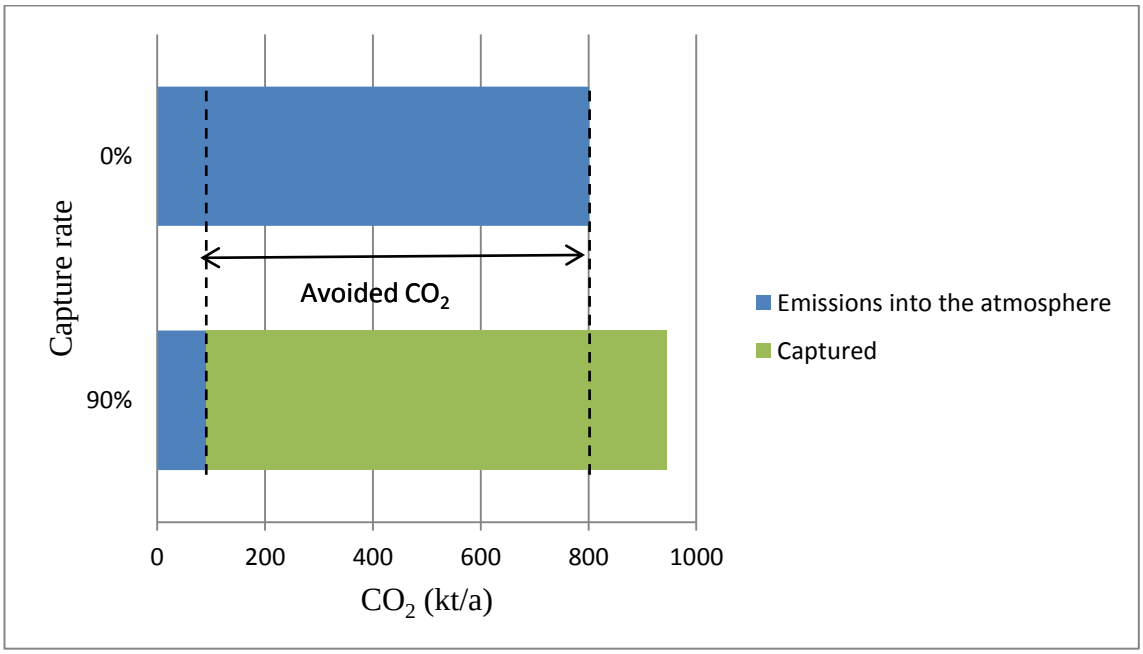


Figure 7.2. *Avoided CO_2 emissions.*

According to a previous study, the ATR pre-combustion capture technology in a CCGT has accomplished CO_2 emissions of 42 kg/MWh in pure electricity production (Kvamsdal et al, 2007).The CO_2 emissions per electricity produced are shown in Figure 7.3.

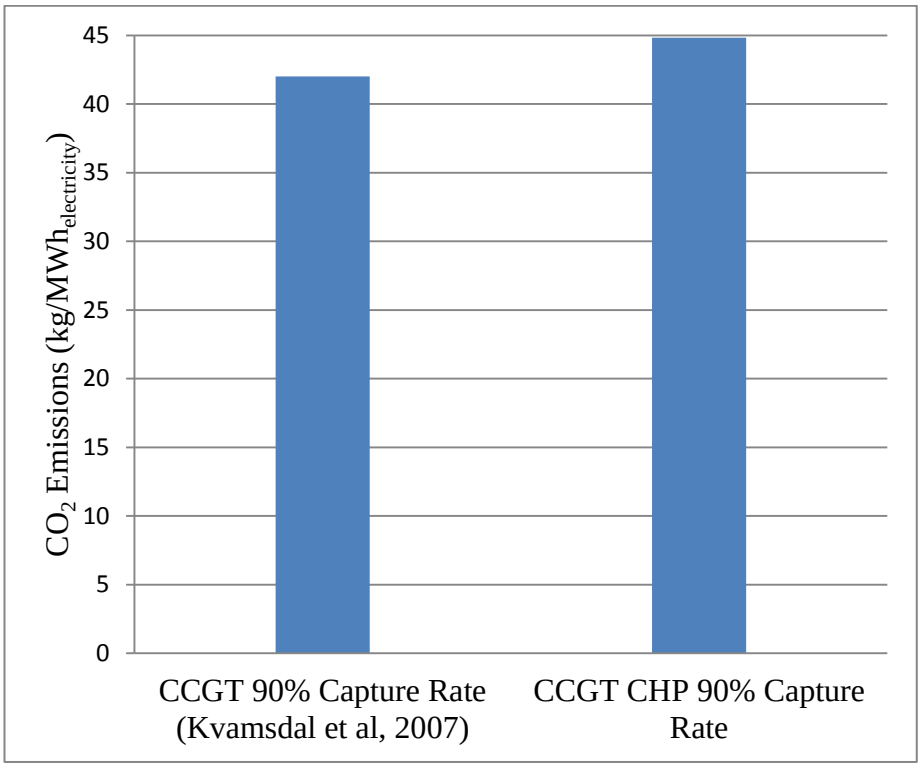


Figure 7.3. *CO_2 emission per electricity produced.*

7.2 Sensitivity Analysis

The different capture rate cases are simulated in such a way that in every case the gas turbine operation is optimal. Thus, the electrical power output of the gas turbine is the same in every case, even though the composition of the gas entering the gas turbine changes. The compositions of these gases are shown in Table 7.2.

Because of the changed composition of the gas, the heating value is different, too. Thus, the amount of gas needed to produce the same amount of electricity in the gas turbine is higher when the capture rate is lower. However, the change in natural gas consumption is minor. This is due to the amount of CO_2 separated in the CO_2 removal unit.

Table 7.2. Synthetic gas entering the gas turbine.

Capture rate		97%	90%	80%
Gas composition before gas turbine (after CO_2 separation) (mol-%)	H_2	46.7	46.1	45.4
	N_2	46.0	45.2	44.4
	CH_4	6.8	6.8	6.7
	CO_2	0.5	1.9	3.5
	SUM	100	100	100

7.2.1 Efficiency

As expected, overall plant efficiency is higher the lower is the capture rate. This is shown in Figure 7.4. Although the electrical output of the gas turbine generator does not change, the electrical output of the steam turbine generator does change. Moreover, district heating power increases when the capture rate decreases.

The rate of change in efficiency increases when the capture rate increases. Efficiency decreases by 0.12%-units from a capture rate of 80% to 90% when the capture rate increases by 1% unit. Efficiency decreases by 0.19 % units from a capture rate of 90% to 97% when the capture rate increases by 1% unit. Thus, the more CO_2 captured, the more fuel is needed to produce the same amount of heat and electricity.

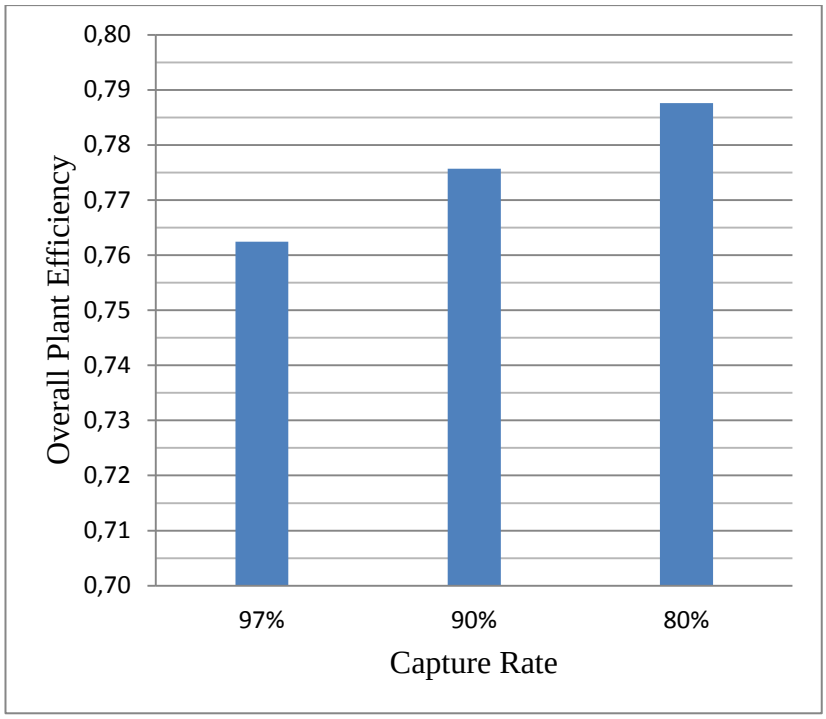


Figure 7.4. *Overall Plant Efficiency.*

7.2.2 Power to Heat Ratio

The change in electricity output from the steam turbine is due to the change in the reboiler duty in the CO_2 separation unit. The steam conducted to the reboiler is extracted from the steam turbine at different pressures, depending on the capture rate. The mass flow of the steam extracted from the steam turbine is larger the higher the capture rate is. The change in capture rate affects almost equally heat production and electricity production. This is shown in Figure 7.5.

The effect of the change in capture rate is equal in both heat and electricity production because of the change in mass flows. The extraction to the absorber unit is larger the higher the capture rate is. This should reduce more heat production than electricity production because the steam extraction to the absorber unit is at the same pressure as the extraction to the district heating heat exchangers. The electricity production of the gas turbine is the same in every capture rate case. The mass flow of fuel entering the gas turbine changes because the heating value of the synthetic gas entering the gas turbine changes. Thus, the natural gas input changes; more heat is produced in the reformer and more steam enters the steam turbine. This is shown in Table 7.3.

Table 7.3. Results from different capture rate cases.

	Capture rate 97%	**Capture rate 90%**	**Capture rate 80%**	**Without CO_2 capture**
Gas turbine electrical output	294 MW	294 MW	294 MW	273 MW
Steam turbine electrical output	147 MW	152 MW	154 MW	130 MW
District heating	348 MW	353 MW	357 MW	351 MW
Absorber unit heat consumption	103 MW	96 MW	86 MW	-
Power-to-heat ratio	1.20	1.20	1.20	1.14

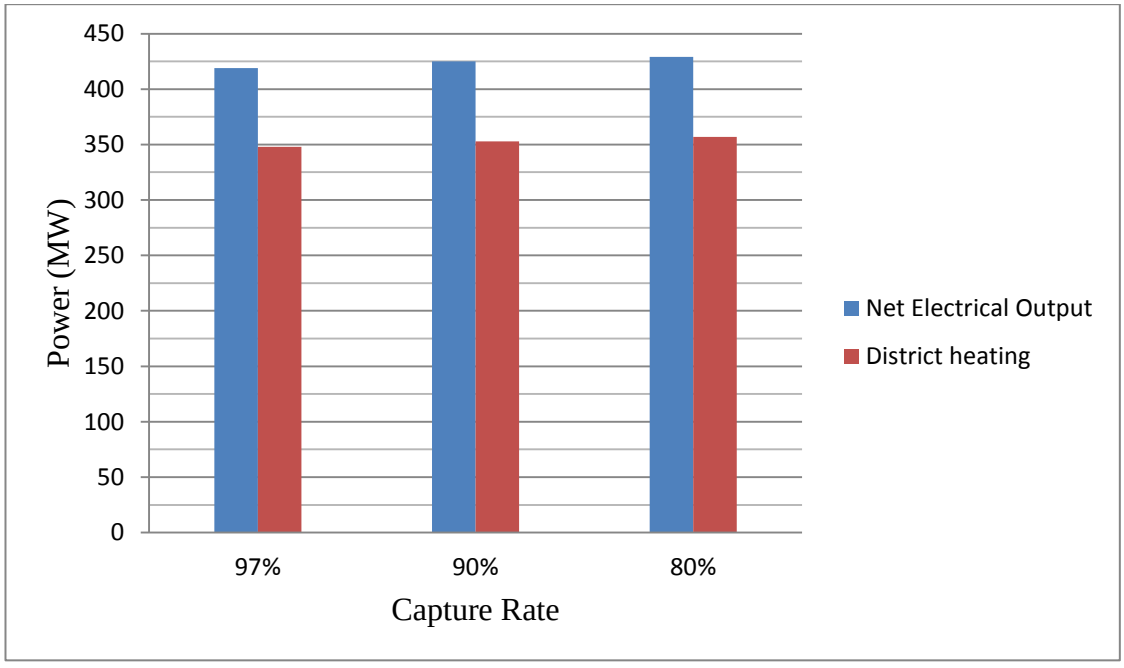


Figure 7.5. *Electrical and heating power.*

7.2.3 CO_2 Emissions and fuel input

Because the natural gas input changes only slightly when the capture rate changes, the change in the amount of the CO_2 captured is the same as the change in the amount of the CO_2 emissions into the atmosphere. This is shown in Figure 7.6.

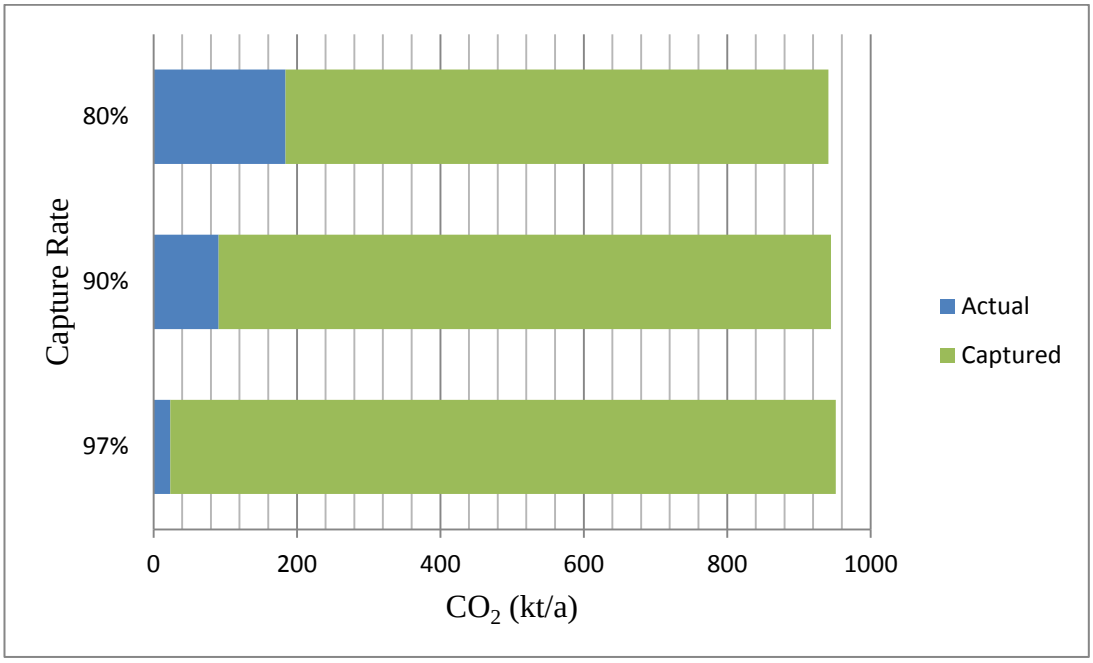


Figure 7.6. *CO_2 emissions with different capture rates.*

This is expected because of the choices made in modeling. The gas turbine produces the same amount of electricity in all of the cases. Thus, it demands roughly the same amount of fuel. Not exactly the same because of the slight change in the composition of the synthetic gas entering the gas turbine. However, it can be concluded from these results that natural gas consumption will grow if the capture rate is increased and the heat production is fixed. This is shown in Figure 7.7, in which the natural gas input is divided by the heat production. Also, the natural gas input is divided by the electricity production in the same figure. In both cases, all the natural gas input is allocated for the other, heat or electricity.

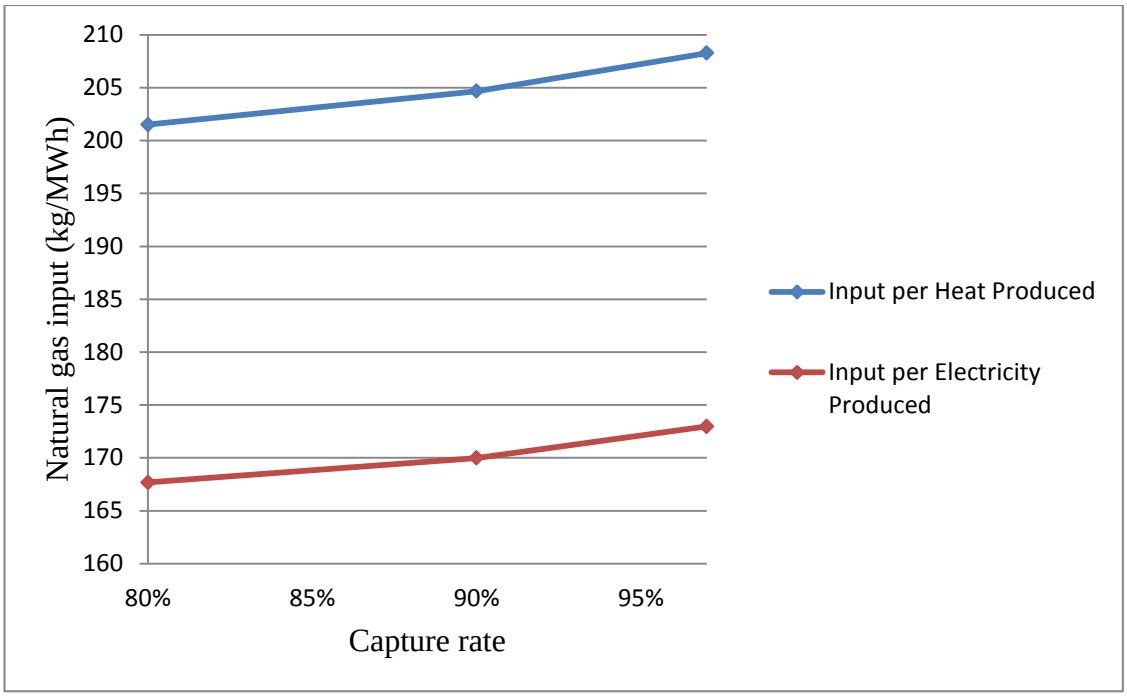


Figure 7.7. *Natural gas input.*

The CO_2 emissions per heat or electricity produced are presented in Figure 7.8. As seen in the figure, the reduction in the CO_2 emission per electricity and heat produced seems linear in the function of capture rate.

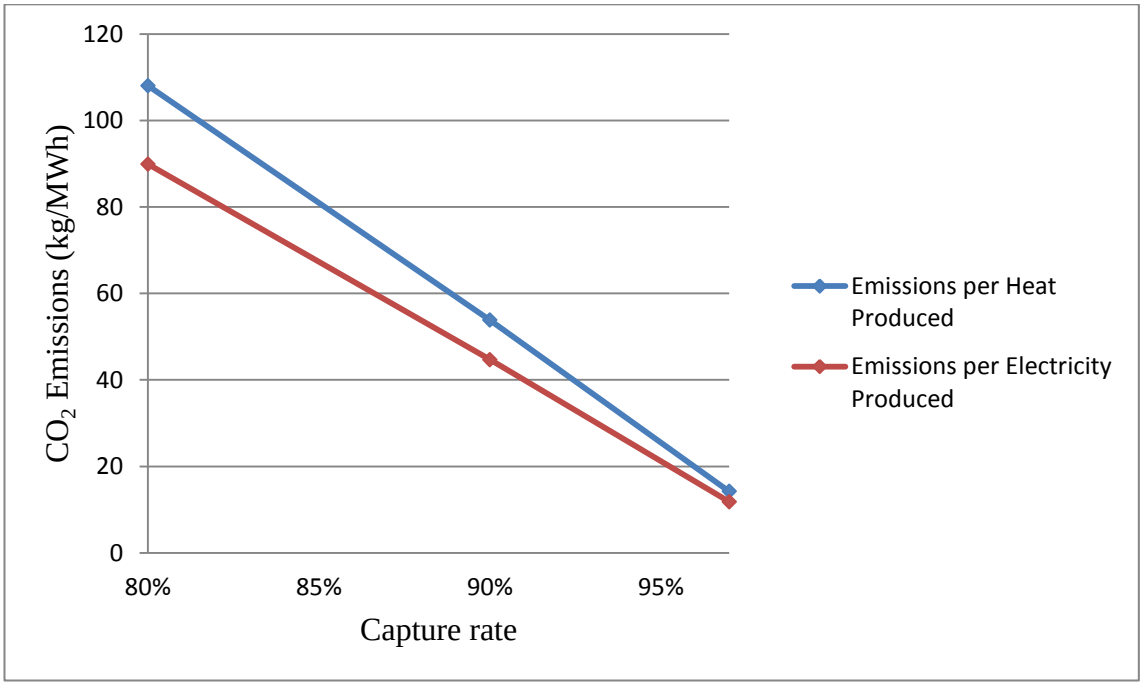


Figure 7.8. *CO_2 emissions per heat and electricity produced.*

However, the change is only almost linear. The rate of change from a capture rate of 80% to 90% is 5.42 kg/MWh_{heat} and 4.52 kg/$MWh_{electricity}$ per 1% change in capture rate. From 90% to 97% the rate of change is higher, 5.66 kg/MWh_{heat} and 4.70 kg/$MWh_{electricity}$ per 1% change in capture rate. Even though the change is so small that it cannot be seen in the figure, it is important because it was noticed previously in this study that efficiency does not change linearly when capture rate changes. Also the natural gas input changed only slightly. Thus, the CO_2 emissions per heat or electricity produced cannot change linearly when capture rate changes.

7.3 Further discussion

The results in the thesis represent only the effects of one possible pre-combustion integration into a new CCGT CHP power plant. Other integrations might cause very different kinds of results. This becomes especially important when the efficiency and power-to-heat ratio parameters are compared.

This is shown when the study of coal CHP CCS case is compared to the case in the thesis. In the coal CHP case, the heat production increased while the total efficiency decreased (Gode and Hagberg, 2008). Thus, the power-to-heat ratio decreased. Here, the power-to-heat ratio increased, while the efficiency decreased significantly. This begs the question of whether it is possible to integrate CO_2 capture into the CCGT CHP in such a way that it would increase the heat production.

It is also possible that efficiency can be improved by different reformer or CO_2 separation technology. Here, the reformer used is an ATR, which burns a fraction CH_4 to provide heat to the system. It might be cheaper to bring the heat into the system from outside. It would also be interesting to investigate whether heat for the CO_2 separation unit could be produced in a way that is cheaper than extracting it from the steam turbine.

In the thesis, the CO_2 capture rate is changed by changing the reboiler duty in the CO_2 separation unit. There are also alternative separation rate changing options. For example, it is possible that not all CH_4 reforms into CO_2 and H_2O in the reformer. If CH_4 is conducted to the gas turbine and combusted, it increases the amount of CO_2 emissions. The capture rate of the CO_2 separation unit would not be the separation rate of the whole system. This might have an effect on the total plant efficiency.

The biggest flaw of the model lies in the assumptions made in the gas turbine operation. Even though it is possible to convert the gas turbine used in the thesis to hydrogen combustion, it is not possible to model this conversion in the scope of this thesis. However, this should not have caused a major inconsistency in the model because the gas turbine unit modeled was able to combust hydrogen.

Another gas turbine parameter that could not be taken into account are NO_X emissions. The temperatures in hydrogen combustion might rise so high that thermal NO_X starts forming. The thermal NO_X formation cannot be calculated, it should be measured. The NO_X emission could be evaluated from the burner information. Because it was assumed that the gas turbine would burn hydrogen, the burners were not given attention. Thus, it is not possible to evaluate NO_X emissions in this thesis.

8 COST RESULTS AND DISCUSSION

The costs of the CCGT CHP with CO_2 capture are estimated in this chapter. The effects of carbon capture on the cost of heat and on the cost of electricity are presented. The cost of avoided CO_2 emissions is also evaluated. Net present value is calculated to study the feasibility of the power plant investment. Because the CO_2 capture system is modeled into a new CCGT CHP here, the feasibility of the entire power plant investment is studied. In other words, the CO_2 capture system investment alone is not studied.

8.1 Costs

The total annual cost is shown in Table 8.1, and the cost of energy in Table 8.2. The cost structure of the power plant is presented in Figure 8.1. The cost of energy is calculated by dividing the total annual cost by the energy produced. It is divided for heat and electricity by using the coefficient 0.9 for heat produced, and then using the energy method. The factors are 0.59 for electricity and 0.41 for heat. Both tables below are calculated from the cost of the first year in operation.

Table 8.1. Total annual cost.

Annualized capital cost	€81 mill.
+ fixed operating cost (wages and maintenance)	€36 mill.
= annual fixed costs	€117 mill.
+ variable operating costs (natural gas, solvents, raw water) multiplied by yearly operating time	€191 mill.
= total annual costs	€308 mill.

Table 8.2. Cost of energy.

Parameter	**Cost (€ / MWh)**
Cost of energy	82
Cost of electricity	90
Cost of heat	75

The cost allocation between heat and electricity is a complicated issue, as mentioned in chapter 4.1. The energy method used here takes into account the fact that the power-to-heat ratio is higher in the case of the CCGT CHP with CO_2 capture than in the case without CO_2 capture. Thus, more costs are allocated for electricity.

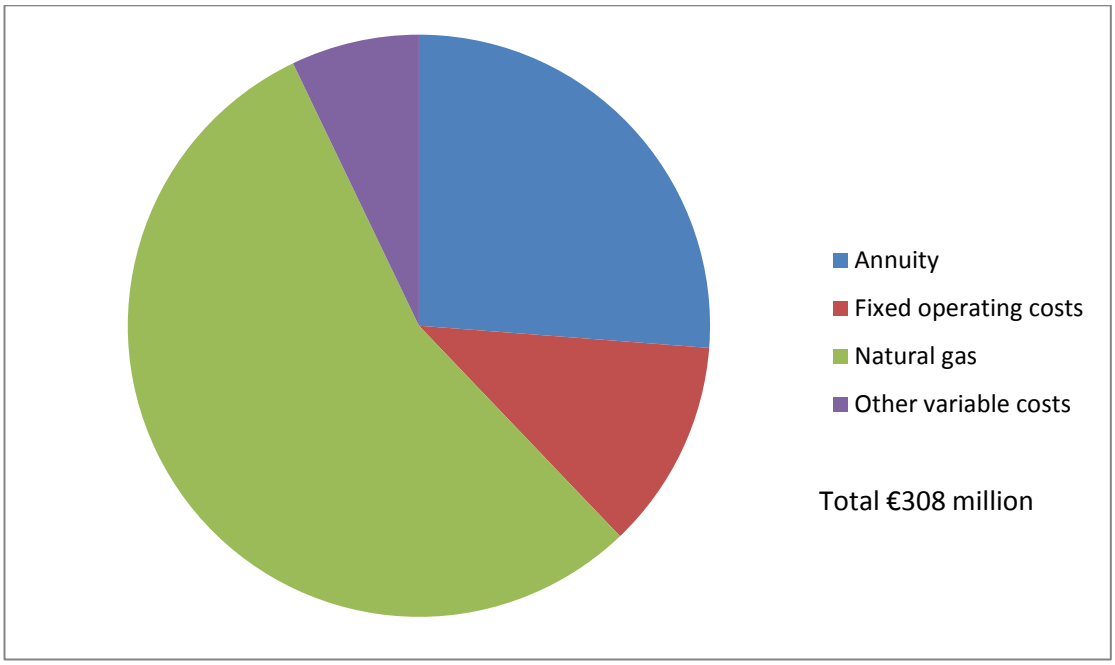


Figure 8.1. *Cost structure.*

As seen in the cost structure figure above, most of the power plant cost comes from the fuel. The price of natural gas strongly affects the costs of the power plant. For comparison, the cost structure of the reference plant is presented in Figure 8.2.

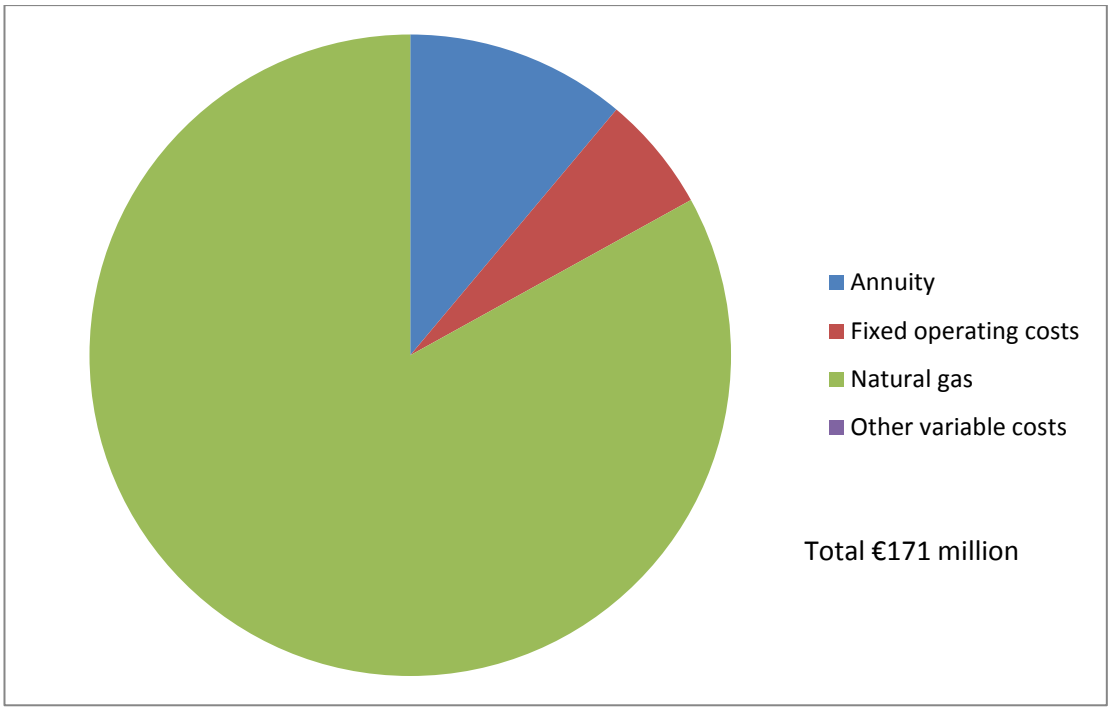


Figure 8.2. *Cost structure of the reference plant.*

As seen in the figure above, the proportion of other variable costs in the case of the reference plant is negligible. Moreover, the proportions of the investment and fixed operation costs are smaller than in the case of the power plant with CO_2 capture. Thus, the price of natural gas has a greater effect on the total cost.

The revenue structure of the power plant with CO_2 capture is presented in Figure 8.3. As the figure shows, most of the revenue the power plant receives comes from the electricity sold. It is also notable, that the proportion of emissions allowances is small. In the case of the reference plant, more revenue comes from electricity than heat, but not significantly.

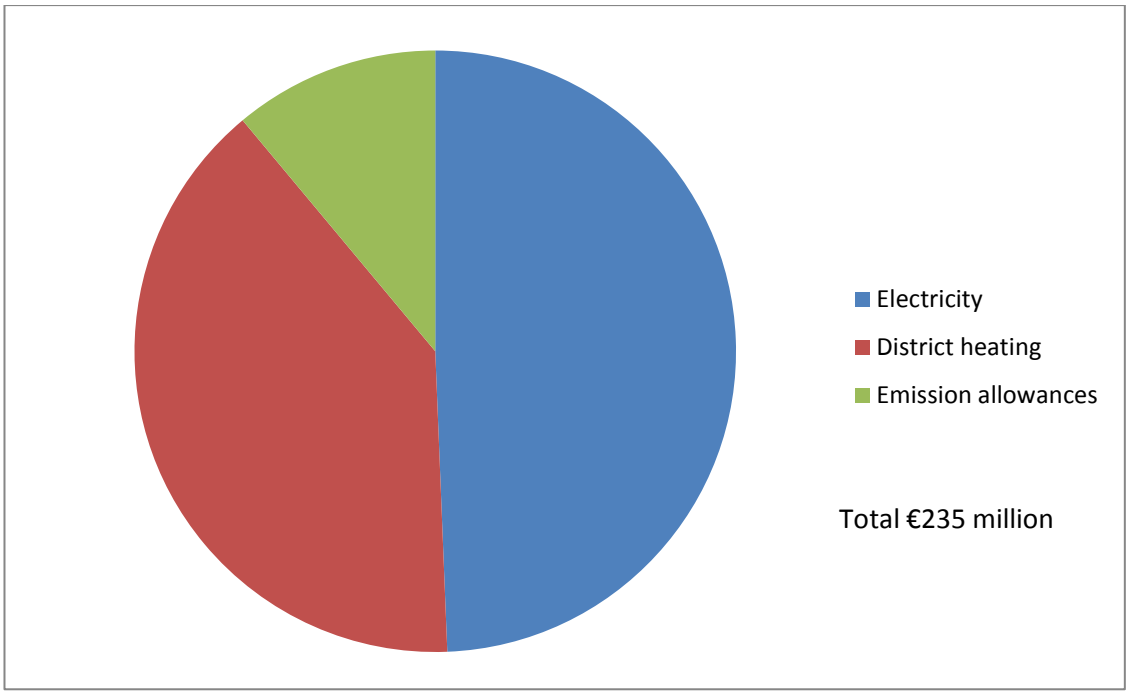


Figure 8.3. *Revenue structure.*

The power plant modeled here has relatively low operating hours. The effect of change in operating hours on the cost of energy is shown in Figure 8.4. As seen in the figure below, when the operating hours increase by 100 h, the cost of energy decreases by €0.60 / MWh.

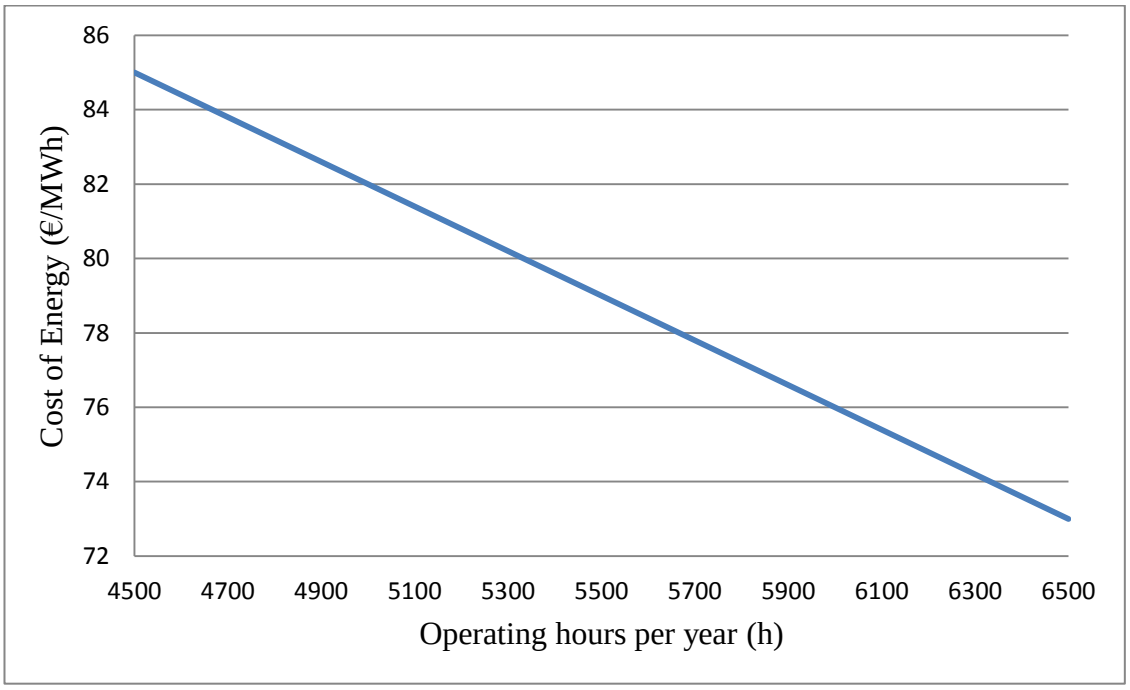


Figure 8.4. *The effect of operating hours on the cost of energy.*

The cost of avoided CO_2 emission is shown in Table 8.3.

Table 8.3. Cost of avoided CO_2 emissions.

Total annual costs	€308 million
– Total annual costs in reference plant	€171 million
Difference in total annual costs	€137 million
/ The amount of avoided CO_2 emissions	711 kt CO_2
Cost of avoided CO_2 emissions	€193/CO_2-tonne

Compared to previous studies, the cost is extremely high. For example, in the VTT report (2011), the cost of avoided CO_2 emissions in a milled peat-fuelled CHP plant is €85/CO_2-tonne. The power plant in the VTT study is smaller, which might suggest that the investment costs are lower. The different results might also be due to different calculation methods when calculating the cost of the power plant without CO_2 capture.

When the CO_2 removal unit was modeled, it was noticed that there was a tradeoff between CO_2 removal heat consumption and solvent leakage. The higher the heat consumption, the lower the leakage is. Here, the CO_2 removal unit is modeled on the basis of an article by Corradetti and Desideri (2005), which gave an approximation for the heat demand. Thus, the leakage did not receive much attention. This might cause high solvent usage and therefore high solvent costs. It is not possible in the scope of this thesis to investigate the tradeoff further.

The cases where most of the leakage solvent is recycled and where none of the leakage solvent is recycled were modeled. However, the possible energy consumption of the recycling was not taken into account. The effect of changed amount of solvent on total annual cost in the first year of operation is shown in Figure 8.5. Linearity is assumed because the energy consumption and other possible influences of the solvent leakage recycling are not taken into account.

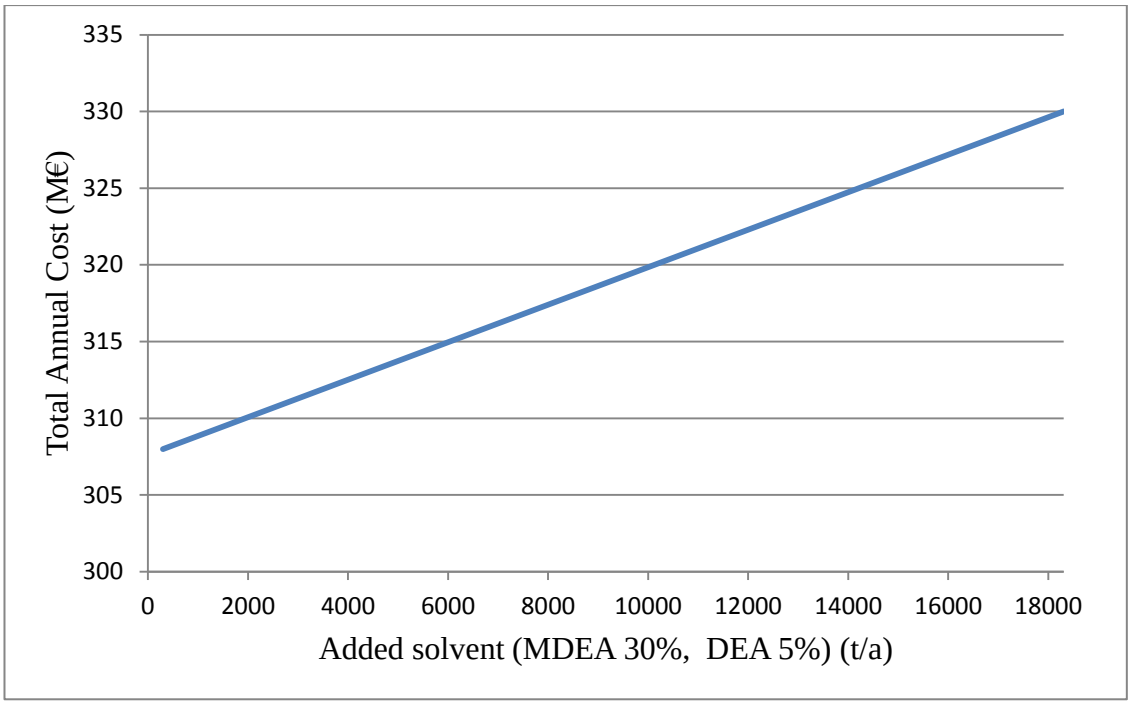


Figure 8.5. *The relationship between total annual cost in the first year of operation and the amount of added solvent.*

As seen in Figure 8.5, if none of the solvent is recycled, the total annual cost increases by 8.8% when compared to the situation where almost of all the solvent is recycled. Compared to previous studies, the lower amount of added solvent seems more likely. In the Foster Wheeler report (2010), the amount of added solvent is less than the lowest case studied here. However, in the Foster Wheeler report (2010) the efficiency is lower. This again indicates the significance of the tradeoff mentioned in the previous chapter.

Even though the recycling of the solvent is not taken into account in the process model results, it is taken into account here. This can be done because it can be assumed that almost all solvent leakage can be recycled without major changes in the process and with minor energy consumption (NETL, 2002). Thus, further on it is assumed that almost all the solvent can be recycled, and the amount of solvent leakage is 302 tonnes per year, which is equal to 91 tonnes per year MDEA and 15 tonnes per year DEA. This is based on the solvent stream calculations in the CO_2 capture model.

8.2 Feasibility of the Investment

The present value of the power plant is calculated with three different interest rates 5%, 7%, and 10%. In all cases the net present value is negative. Thus, the power plant investment is not feasible in the assumed scenario.

Besides the price of reformer, the factors that affect the feasibility of the the investment the most are the prices of electricity, heat, emission allowance and natural gas. The boundary values for these factors are presented in Table 8.4. The boundary value here is the value when the net present value is zero. In other words, if the value of the factor is more than the boundary value, the investment becomes feasible. Except in the case of natural gas, where the value should be lower to make the investment feasible.

Table 8.4. Boundary values.

Factor	**Boundary Price**
Electricity	€85 / MWh
District Heating	€88 / MWh
Emission Allowance	€96 / CO_2-tonne
Natural Gas	€19 / MWh

As seen in the table above, the boundaries are high for electricity, district heating and emission allowance prices. The boundary price for natural gas is low. However, there is a strong relationship between the prices of electricity and emission allowances in the Nordic market and it cannot be assumed that just one of them would change without the other changing.

The boundary price of emission allowance is much lower than the price of avoided CO_2 emissions, €193 / MWh. This is because the cost of a CCGT CHP without CO_2 capture affects the cost of avoided CO_2 emissions, but not directly the feasibility of the CCGT CHP with CO_2 capture. The feasibility is calculated with the net present value, and the cost of avoided CO_2 emissions from the differences between the CCGT CHP with and without CO_2 capture. Also, the amount of avoided CO2 emissions is less than the amount of CO_2 captured, which is here assumed to be the number of CO_2 emission allowances sold.

It is reasonable to compare how changes in more than one component affect the feasibility. The boundary price of natural gas as a function of the price of the emission allowance is presented in Figure 8.6. The figure is calculated by keeping the net present value as zero and changing the price of the emission allowance.

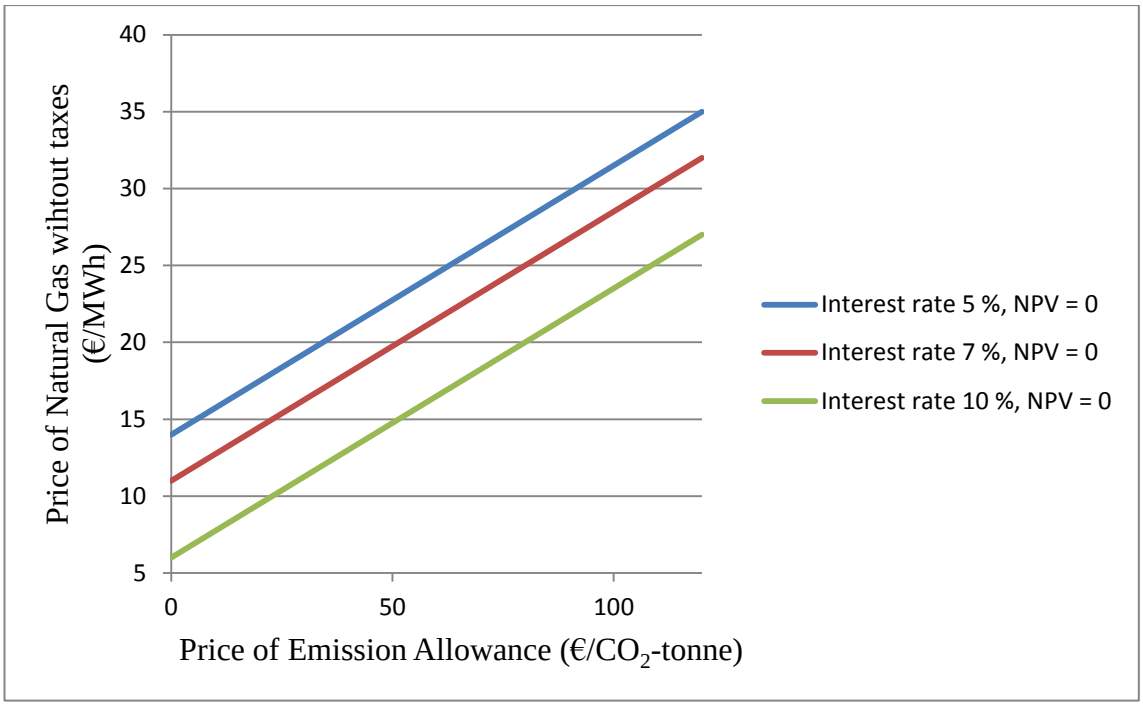


Figure 8.6. *The price of natural gas as a function of the price of emission allowances when the net present value is zero.*

The price of natural gas was between €27/MWh and €43/MWh from January 2010 to May 2011 (SVT, 2011). The increased tax rate has increased the price of natural gas from the beginning of 2011 (SVT, 2011). As seen in the figure above, the natural gas price of €32 / MWh yields an emission allowance price of €100 / CO_2-tonne to make the power plant investment feasible. This is an extremely high value. Currently, the emission allowance price is €11 / CO_2-tonne (EEX, 3 August 2011). Even though the emission allowance price is expected to increase, the price of natural gas should decrease, too, to make the investment feasible.

The boundary price of electricity as a function of the price of natural gas is presented in Figure 8.7. The net present value is kept as zero.

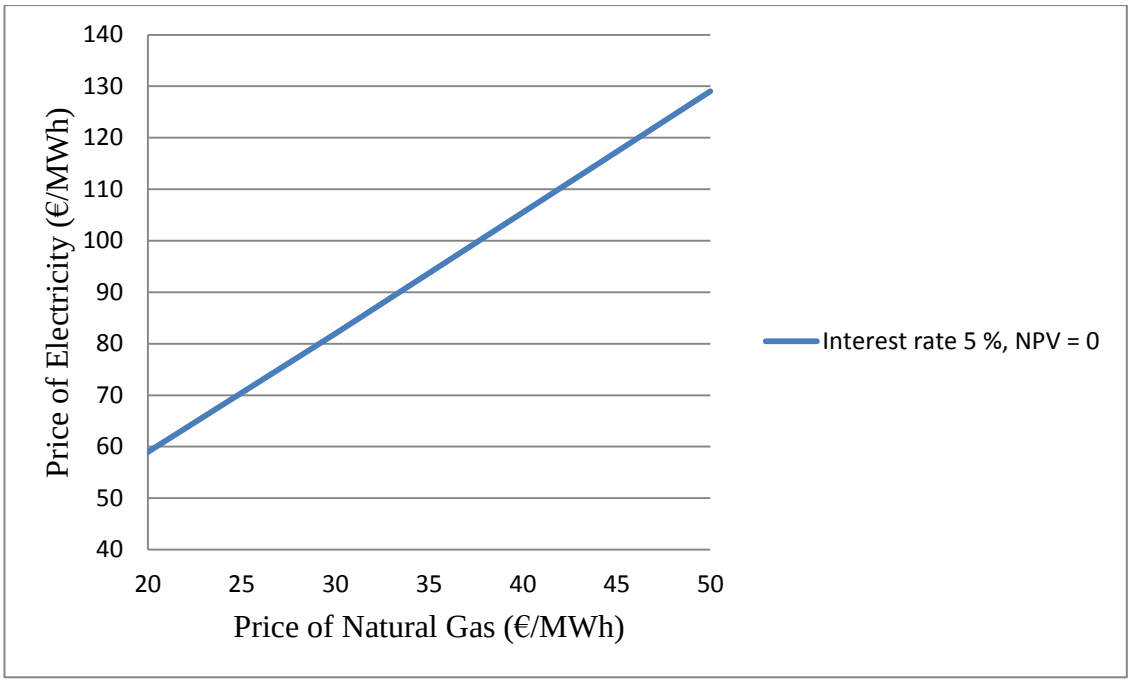


Figure 8.7. *The price of electricity as a function of the price of natural gas when the net present value is zero.*

As seen in the figure above, the price of natural gas strongly affects the boundary price of electricity. This is not surprising, as natural gas is the largest operating cost. When the price of natural gas changes by €1 / MWh, the price of electricity changes by €2.3 / MWh. This higher rate of change in the price of electricity is due to the efficiency of the power plant. The efficiency of the power plant also affects the price of district heating. The price of natural gas as a function of the price of district heating is shown in Figure 8.8.

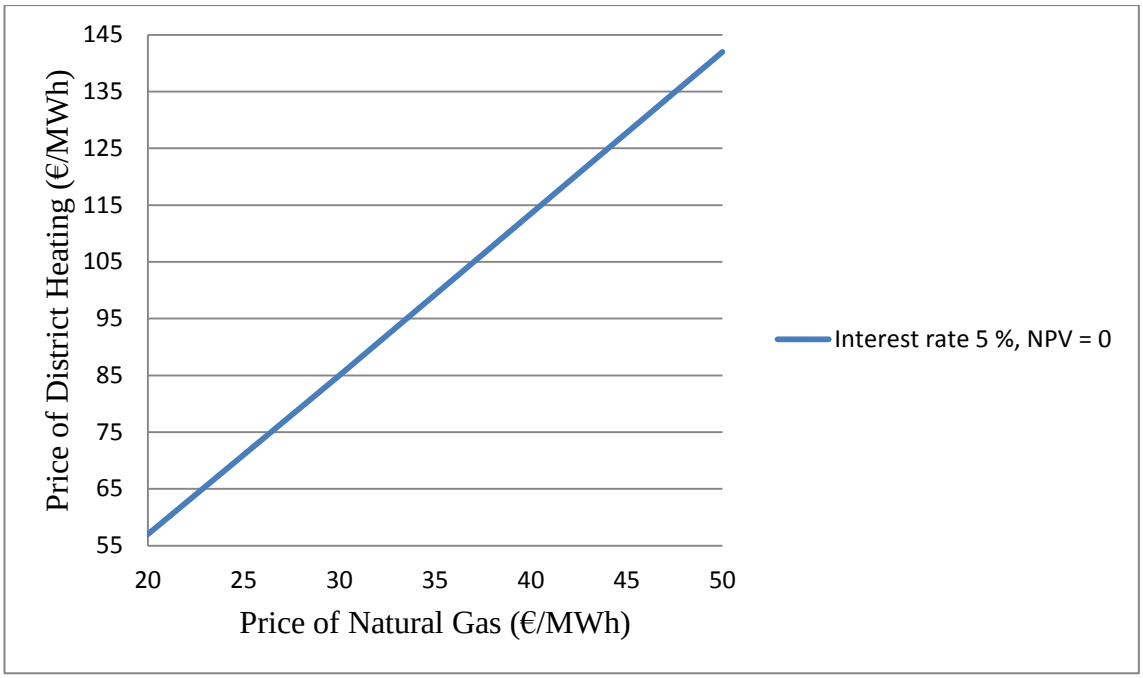


Figure 8.8. *The price of natural gas as a function of the price of heat when the net present value is zero.*

The price of electricity as a function of the price of emission allowance is presented in Figure 8.9. As seen in the figure, the higher the price of emission allowances, the lower the price of electricity needed for the investment to be feasible.

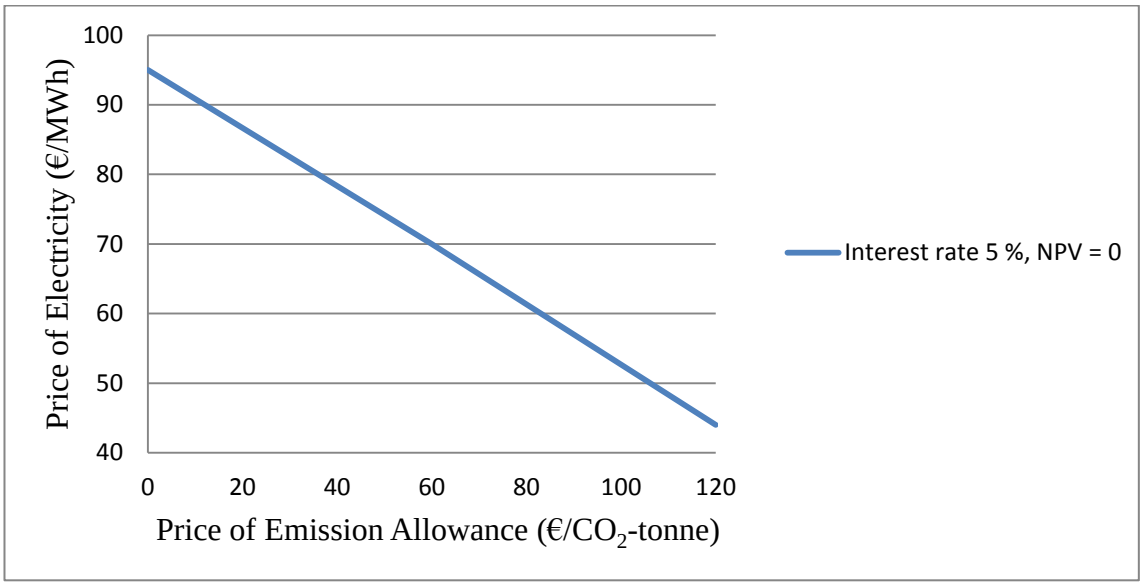


Figure 8.9. *The price of electricity as a function of the price of emission allowances when the net present value is zero.*

However, in the real market situation it is expected that the emission allowances will raise the price of electricity. The cost of emissions increases the total cost of power plants that do not adopt CO_2 capture. The plants that do adopt CO_2 capture will have the cost increase from the adoption but also a new source of revenue from emission allowances.

In the reference case, the net present value is positive with the assumed values. The limit between the parties having the conventional CCGT CHP cheaper and having the CCGT CHP with CO_2 cheaper. This is presented in Figure 8.10. The feasibility of the CCGT CHP with and without CO_2 capture is compared with different electricity and emission allowance prices in the figure. The feasibility of the CCGT CHP without CO_2 capture is calculated as in the case with CO_2 capture by setting the net present value as zero.

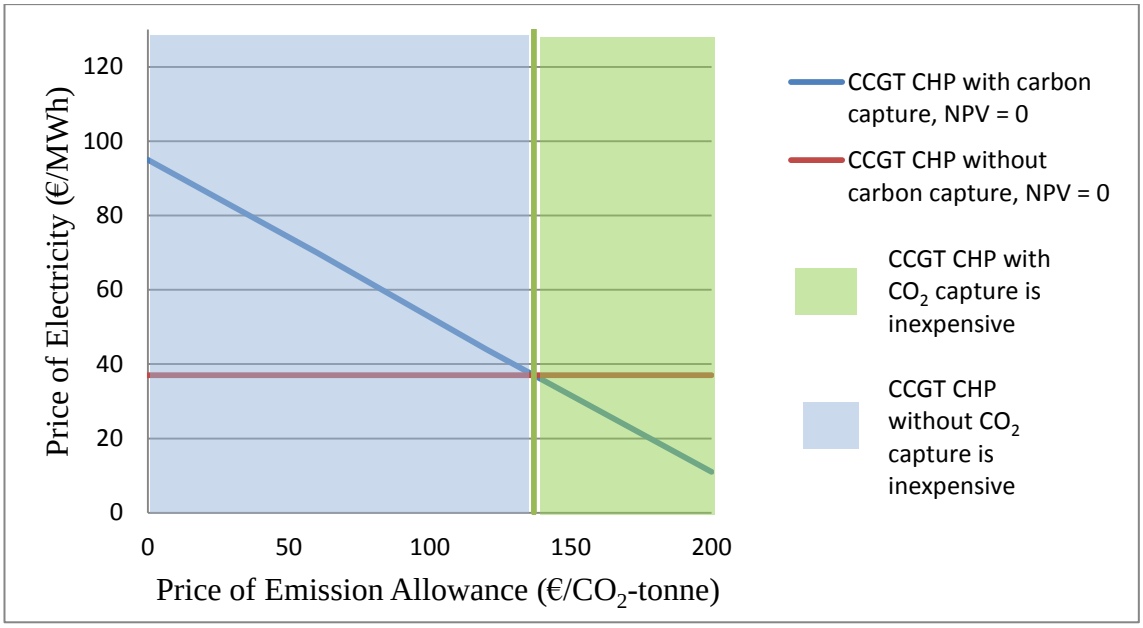


Figure 8.10. *Feasibility of CCGT with and without CO_2 capture.*

As seen in the figure above, the boundary value where the power plant with CO_2 capture becomes cheaper than the power plant without CO_2 capture is €137 / CO_2-tonne. In the blue area, which is below the €137 / CO_2-tonne emission allowance price, the CCGT CHP without CO_2 capture would be a better investment. In the green area, the CCGT CHP with CO_2 capture would be a better investment. The boundary price is high and suggests that the power plant investment with CO_2 capture would not be feasible. The boundary price calculated here is higher than the boundary prices calculated at the beginning of this chapter, where the boundary price was calculated so that the NPV is zero. Here it is compared with the CCGT CHP without CO_2 capture.

The cost of CO_2 emissions is analyzed in three different ways in the thesis. The results are summarized in Table 8.5.

Table 8.5. The boundary prices for emission allowances.

Boundary price	**€ / CO_2-tonne**
Cost of avoided CO_2 emissions	193
Emission allowance when the NPV of CCGT CHP with CO_2 capture equals zero	96
Emission allowance when the NPV of CCGT CHP with and without CO_2 capture equals zero	137

The differences are due to different calculation methods. In the cost of avoided CO_2 emissions only the avoided emissions are taken into account, and the costs that are divided by the amount of emissions constitute the difference between the total annual costs of the CCGT CHP with and without CO_2 capture. In the second case in the table above, only the costs of the CCGT CHP with CO_2 capture are taken into account, and the price of emission allowances are calculated by setting the NPV as zero. In the third case in the table, the price of emission allowance is calculated by setting the NPV of the CCGT CHP with and without CO_2 capture as zero.

8.3 Further discussion

As mentioned in the cost assumptions in chapter 6, the cost of the power plant is not calculated from the component prices, as such information was not directly available. However, reliable cost information that had to be scaled was found. This might be a source of error in the cost calculations.

Another possible error source in the feasibility calculations is the reliability of the market information. The price information found for the emission allowance was hardly high enough to cover the cost information found for the transportation and storage. Thus, it cannot cover all the costs caused by CCS, which also include the costs of CO_2 capture. This requires further market analysis to see how the prices can develop. Here, it was also assumed that all captured CO_2 could be sold as emission allowances. This would most likely not be the case, and it would also affect the relationship of the cost of transportation and storage and the price of emission allowances on the market.

9 SUMMARY AND CONCLUSIONS

The research question was: how does carbon capture affect a new gas turbine combined cycle power plant with combined heat and power production? The effects on total plant efficiency, electricity production efficiency, power-to-heat ratio, fuel input, CO_2 emissions, CO_2 avoidance cost and cost of electricity and heat production, especially, were studied, and a sensitivity analysis was made.

Different CO_2 capture technologies were briefly compared in the thesis. Based on the comparison, a pre-combustion technology was chosen to be modeled. The technology was modeled in a greenfield CCGT CHP power plant. The model was built with the Solvo ®, MS Excel ®, and the AspenPlus ®.

The power plant was planned to be located on the coast of Finland. Heat demand in the area of the site was the basis for the size of the power plant. The plant modeled produces 353 MW of heat. Many assumptions had to be made when building the model, especially in the cost evaluation.

The power plant modeled in the thesis is not feasible. The costs are high, and to cover the costs of CO_2 capture the emission allowance prices should be extremely high. It is concluded that CCGT CHP with pre-combustion technology would not be a reasonable investment with the current prices of electricity, heat, and emission allowances. The main strengths of the plant were low rate of emissions and increased power-to-heat ratio. The main weaknesses were high investment costs and decreased efficiency. The results here are not completely in line with previous studies.

The thermodynamic results are fairly well in line with the previous studies. The efficiency of the plant is lower than in the reference case. Compared with previous studies, the amount of the decrease was surprisingly high. There are only a few previous studies on CHP plants and, consequently, there were no expectations regarding the power-to-heat ratio. The power-to-heat ratio increased slightly. Thus, the decrease in efficiency affects heat production more than electricity production.

The cost results differ greatly from the previous studies. The cost of avoided CO_2 emissions here is approximately twice as high as in the previous studies. The main parameters affecting the cost of avoided CO_2 emissions were the high investment cost and low price of emission allowances.

In the thesis, the entire power plant was modeled and it has been found that all the components require further attention. In particular, the integration between the reformer and the HRSG, and the absorber with the rest of the process requires further attention. The cost results are based on simple assumptions, which might not be feasible. A complete market analysis might give more accurate price information and change the results.

REFERENCES

2Co Energy. 2011. Don Valley Power Project. Available from http://www.2coenergy.com/dv_project_description.html. Accessed on 2.8.2011.

AACE, American Association of Cost Engineers. 2011. Available from http://www.aacei.org/mbr/whatIsCE.shtml. Accessed on 22.2.2011.

Aspen Tech. 2011. Available from http://www.aspentech.com/products/aspen-plus.aspx. Accessed on 27.4.2011.

Bill. 2010. Hallituksen esitys Eduskunnalle laiksi uusiutuvilla energialähteillä tuotetun sähkön tuotantotuesta. HE 152/2010 vp. Available from http://www.finlex.fi/fi/esitykset/he/2010/20100152.pdf. Accessed on 3.8.2011.

Bolland, Olav; Nord, Lars. 2011. HRSG Design for Integrated Reforming Combined Cycle With CO2 Capture. Journal of Engineering for Gas Turbines and Power. Vol. 133.

Corradetti, Alessandro; Desideri, Umberto. 2005. Analysis of Gas-Steam Combined Cycles With Natural Gas Reforming and CO2 Capture. Journal of Engineering for Gas Turbines and Power. Vol. 127. pp.545-552.

Damen, Kay; van Troost, Martijn; Faaij, André, Turgenburg, Wim. 2006. A comparison of electricity and hydrogen production system with CO2 capture and storage. Part A: Review and selection of promising conversion and capture technologies. Progress in Energy and Combustion Science. Vol. 32. pp.215-246.

EEX, European Energy Exchange. 2011. Emissions rights. Available from http://www.eex.com/en/Market%20Data/Trading%20Data/Emission%20Rights. Accessed on 22.7.2011.

Energiateollisuus. 2011. District heating prices. Available from http://www.energia.fi/fi/tilastot/kaukolampotilastot/kaukolammonhinta. Accessed on 3.8.2011.

Energy Policy for Europe. 2007. Available from http://eur-lex.europa.eu/Notice.do?mode=dbl&lang=en&ihmlang=en&lng1=en,fi&lng2=cs,da,de,el,en,es,et,fi,fr,hu,it,lt,lv,mt,nl,pl,pt,sk,sl,sv,&val=441123:cs&page. Accessed on 10.8.2011.

EU, European Commission. 2011. Seventh Framework. Available from http://cordis.europa.eu/fetch?CALLER=FP7_PROJ_EN&QZ_WEBSRCH=carbon+capture&USR_SORT=EN_QVD+CHAR+DESC. Accessed on 18.2.2011.

EU, European Commission. 2010. Energy 2020 A strategy for competitive, sustainable and secure energy. Comminication from the Commission to the Europen Parliament, the Council, the Europen Economis and Social Committee and the Committee of the Regions. Brussels. Europen Commission.

European Commission. 2010. Emissions Trading System (EU ETS). Available from http://ec.europa.eu/clima/policies/ets/index_en.htm. Accessed on 3.8.2011.

European Commission. 2010. Decision. Official Journal of the European Union. 2010/670/EU. Available from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:290:0039:0048:en:PDF. Accessed on 9.8.2011.

EU. 2009. Directive 2009/31/EC of the European Parliament and of the Council. Official Journal of the European Union. pp. L140/116-L140/117, L140/123.

European Commission. 2007. Directive 2009/31/EY. Hiilidioksidin geologinen varastointi. Euroopan Unionin virallinen lehti. Available from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0114:0135:FI:PDF. Accessed on 10.8.2011.

Fortum Oy. 2011. Solvo ®. Available from http://solvo.fi/index_en.shtm. Accessed on 27.4.2011.

Fortum Oy. 2011. Heat consumption data. Received 14.3.2011.

Fortum Oy. 2010. Fortum to discontinue Meri-Pori carbon capture and storage project. Available from http://www.fortum.com/en/mediaroom/pages/fortum-to-discontinue-meri-pori-carbon-capture-and-storage-project.aspx. Accessed on 2.8.2011.

Fortum Power and Heat Oy. 2010. Energiaa Suomenojan voimalaitokselta. [brochure] Visited 27.1.2011.

Foster Wheeler Ltd., Fortum Oy. 2010. Assessment of Natural Gas Fuelled Power Plants with Carbon Capture. [Confidential Report]

Fourier, Josep. 1836. General Remarks on the Temperature of the Terrestrial Globe and the Planetary Spaces. Translated from French by Mr. Ebenezer Burges of Ambers College. The American Journal of Science. Vol. 32. No. 1.

Gasum Oy. 2011. Natural Gas Composition. Available from https://online.gasum.fi/online/yleisettiedot/Sivut/Maakaasun_koostumus.aspx. Accessed on 28.6.2011.

Global CCS Intitute. 2011. Available from http://www.globalccsinstitute.com/resources/projects/map. Accessed on 18.2.2011.

Gode, J.; Hagberg, L.. 2008. Systemanalys av CCS vid kraft värme. Available from http://www.ivl.se/download/18.7df4c4e812d2da6a416800072060/B1870.pdf. Accessed on 18.7.2011.

Haverila, Matti; Uusi-Rauva, Erkki; Kouri, Ilkka; Miettinen, Asko. 2005. Teollisuustalous. 5th edition. Tammerpaino Oy.

Horlock, J.H.. 1992. Combined Power Plants Including Combined Cycle Gas Turbine (CCGT) Plants. Pergamon Press Ltd.

ICIS. 2010. Available from http://www.icispricing.com/il_shared/Samples/SubPage10100082.asp. Accessed on 1.7.2011.

ICIS. 2008. Available from http://www.icis.com/Articles/2008/06/16/9132093/diethanolamine-prices-rocket-on-demand-from-china-and-for-biofuels.html. Accessed on 1.7.2011.

IEA, International Energy Agency. 2008. Carbon Capture and Storage A key carbon abatement option. Paris. IEA Publications. pp. 47-53.

IEA, International Energy Agency, 2010. Energy Technology Perspectives 2010 Scenarios & Strategies to 2050. Paris. IEA Publications. p.47, p.120.

IEA graphs, International Energy agency. 2010. Energy Technology Perspectives 2010, Key Graphs. Available from http://iea.org/techno/etp/etp10/key_figures.pdf. Accessed on 26.1.2011.

IFRF; Raiko, Risto; Saastamoinen, Jaakko; Hupa, Mikko; Kurki-Suonio, Ilmari. 2002. Poltto ja palaminen. Gummerus Kirjapaino. p. 24.

IPCC, International Panel of Climate Change. 2005. Carbon Capture and Storage. USA. Cambridge University Press. p.118.

Johnston, Lucy; Hausman, Ezra; Biewald, Bruce; Wilson, Rachel; White, David. 2011. 2011 Carbon Dioxide Price Forecast. Synapse Energy Economics Inc.Available from http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf. Accessed on 3.8.2011.

Jonshagen, Klas; Sipöcz, Nikolett; Genrup, Magnus. 2011. A novel Approach of Retrofitting a Combined Cycle With Post Combustion CO2 Capture. Journal of Engineering for Gas Turbines and Power. Vol. 133.

Kangas, Hanna-Liisa. 2007. Euroopan Unionin maakaasumarkkinoiden kehitys vuoteen 2030: maakaasumarkkinamalli. Pro Gradu. University of Helsinki. Available from http://www.helsinki.fi/taloustiede/tutkimus/ye/graduhannakangas.pdf. Accessed on 3.8.2011.

Kaplan, Stan. 2008. Congressional Research Service Report for Congress. Power Plants: Characteristics and Costs. Available from http://www.fas.org/sgp/crs/misc/RL34746.pdf. Accessed on 23.2.2011.

Kehlhofer, Rolf H.; Warner, Judy; Nielsen, Henrik; Bachmann, Rolf. 1999. Combined-Cycle Gas & Steam Turbine Power Plants. 2nd Edition. PennWell Publishing Company.

Kohl, Arthur; Nielsen, Richard. 1997. Gas Purification. 5th Edition. Gulf Publishing Company.

Koskelainen, Antti. 2010. Euroopan sähkömarkkinaintegraatio. Suomen ElFi Oy. Available from http://www.fingrid.fi/attachments/fi/media/Seminaarit/sm2010/elfi_koskelainen.pdf. Accessed on 9.8.2011.

Kvamsdal, Hanne M.; Jordal, Kristin; Bolland, Olav. 2006. A Quantitative Comparison of gas turbine cycles with CO2 capture. Energy. Vol. 32. Issue 1. pp. 10-24.

Laatikainen, Tuula. 2011. Uusiutuva myllertää Euroopan sähkömarkkinoita: kohta tuottaja maksaakin kuluttujalle. Tekniikka ja talous. Available from http://www.tekniikkatalous.fi/energia/uusiutuva+myllertaa+euroopan+sahkomar

kkinoita+kohta+tuottaja+maksaakin+kuluttajalle/a601911. Accessed on 9.8.2011.

McKinsey & Company. 2010. Impact of the financial crisis on the carbon economics. Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve. available from http://209.172.180.115/clientservice/sustainability/pdf/Impact_Financial_Crisis_Carbon_Economics_GHGcostcurveV2.1.pdf. Accessed on 21.7.2011.

Microsoft. 2011. Available from http://office.microsoft.com/en-us/excel-help/office-excel-2007-product-overview-HA010165632.aspx?CTT=1. Accessed on 27.4.2011.

National Grid. 2006. Available from http://www.nationalgrid.com/uk/sys_06/print.asp?chap=all. Accessed on 24.2.2011.

Neilimo, Kari; Uusi-Rauva, Erkki. 2007. Johdon laskentatoimi. Edita Publishing Oy. 6th – 8th edition. pp. 206-225.

NER300. 2011. Finance for installations of innovative renewable energy technology and CCS in the EU. Available from http://www.ner300.com/. Accessed on 10.8.2011.

NETL National Energy Technology Laboratory. 2011. Available from http://www.netl.doe.gov/technologies/carbon_seq/index.html. Accessed on 18.2.2011.

NETL, National Energy Technology Laboratory. 2010. Cost and Performance Baseline for Fossil Energy Plants. Volume 1: Bitonious Coal and Natural Gas to Electricity. Available from http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_Rev2.pdf. Accessed on 3.2.2011.

NETL, National Energy Technology Laboratory. 2002. ASPEN Plus Simulation of CO2 Recovery Process. Available from http://www.osti.gov/bridge/servlets/purl/810497-igyB4P/native/810497.pdf. Accessed on 15.7.2011.

Nord Pool. 2011. Electricity prices. Available from http://www.nordpoolspot.com/reports/areaprice/Post.aspx. Accessed on 3.8.2011.

Okasanen, A.. 2010. ENER-6010 Polttotekniikka. Tampere University of Technology. Energy and Process technology. Power plant and combustion technology. Lecture reading for Combustion Technology course, fall 2010.

Power Engineering. 2011. UK's Energy Technologies Institute launches CCS for gas plants project. Available from http://www.power-eng.com/articles/2011/04/uk-s-energy-technologies.html. Accessed on 2.8.2011.

Rackley, Stephen A.. 2010. Carbon Capture and Storage. Elsevier Inc. p.69, 73, 76.

Raiko, Markku. 2011. Ph.D. (Tech); Senior Advisor; ÅF Consult Ltd. CCGT cost information [private email]. Recipient Leena Björn. Sent 21.6.2011 12:54 AM (GTM +0200).

Ramgen Power Systems LCC. 2009. Available from http://www.powermag.com/business/1939.html. Accessed on 29.6.2011.

Siemens. 2011. Available from http://www.energy.siemens.com/mx/pool/hq/services/power-generation/product-related-services/downloads/Fuel-Conversion_Flyer_a96001-u90-b210-x-4a00.pdf. Accessed on 27.4.2011.

SSE Generation Limited. 2011. CCS Project at Peterhead. Available from http://www.sse.com/PressReleases2011/CCSPeterhead/. Accessed on 2.8.2011.

Koskelainen, Antti. 2010. Euroopan sähkömarkkinaintegraatio. Available from http://www.fingrid.fi/attachments/fi/media/Seminaarit/sm2010/elfi_koskelainen.pdf. Accessed on 3.8.2011.

SVT, Suomen virallinen tilasto. 2011. Kasvihuonekaasut. Available from http://www.stat.fi/til/khki/2009/khki_2009_2011-04-28_tau_002_fi.html. Helsinki. Tilastokeskus. Accessed on 6.7.2011.

SVT, Suomen virallinen tilasto. 2008. Labor costs. Available from http://www.stat.fi/til/tvtutk/2008/tvtutk_2008_2010-10-22_tau_001_fi.html. Helsinki. Tilastokeskus. Accessed on 14.7.2011.

SVT, Suomen virallinen tilasto. 2011. Energian hinnat. Available from http://www.stat.fi/til/ehi/tau.html. Accessed on 20.7.2011.

TCM, Technology Centre Mongstad. 2011. Available from http://www.tcmda.com/en/. Accessed on 2.8.2011.

Tullihallitus. 2011. Asiakasohje Nro. 21. Available from http://www.tulli.fi/fi/suomen_tulli/julkaisut_ja_esitteet/asiakasohjeet/valmisteverotus/tiedostot/021.pdf. Accessed on 3.8.2011.

UNFCCC, United Nation Framework Convention on Climate Change. Kyoto Protocol. available from http://unfccc.int/kyoto_protocol/items/2830.php. Accessed on 3.2.2011.

Vanek, Francis; Albright, Louis D.. 2008. Energy Systems Engineering: Evaluation and Implementation. McGraw-Hill Professional Publishing. pp. 23-75.

VTT. 2004. Energia Suomessa, Tekniikka, talous ja ympäristövaikutukset. 3rd edition. Helsinki. Edita Prima Oy.

VTT; Teir, Sebastian; Hetland, Jens; Lindeberg, Erik; Torvanger, Asbjörn; Buhr, Katarina; Koljonen, Tiina; Gode, Jenny; Onarheim, Kristin, Tjernshaugen, Andreas, Arasto, Antti; Liljeberg, Marcus; Lehtila, Antti; Kujanpää, Lauri; Nieminen, Matti. 2010. Potential for carbon capture and storage (CCS) in the Nordic region. Helsinki. VTT. pp. 24-52.

VTT; Teir, Sebastian; Arasto, Antti; Tsupari Eemeli; Koljonen, Tiina; Kärki, Janne; Kujanpää, Lauri; Lhetilä; Antti; Nieminen, Matti. 2011. Hiilidioksidin talteenoton ja varastoinnin (CCS:n) soveltaminen Suomen olosuhteissa. Helsinki. VTT.

Westney, Richard. 1997. Engineer's cost handbook: tools for managing project cost. Marcel Decker Inc. pp.41-111.

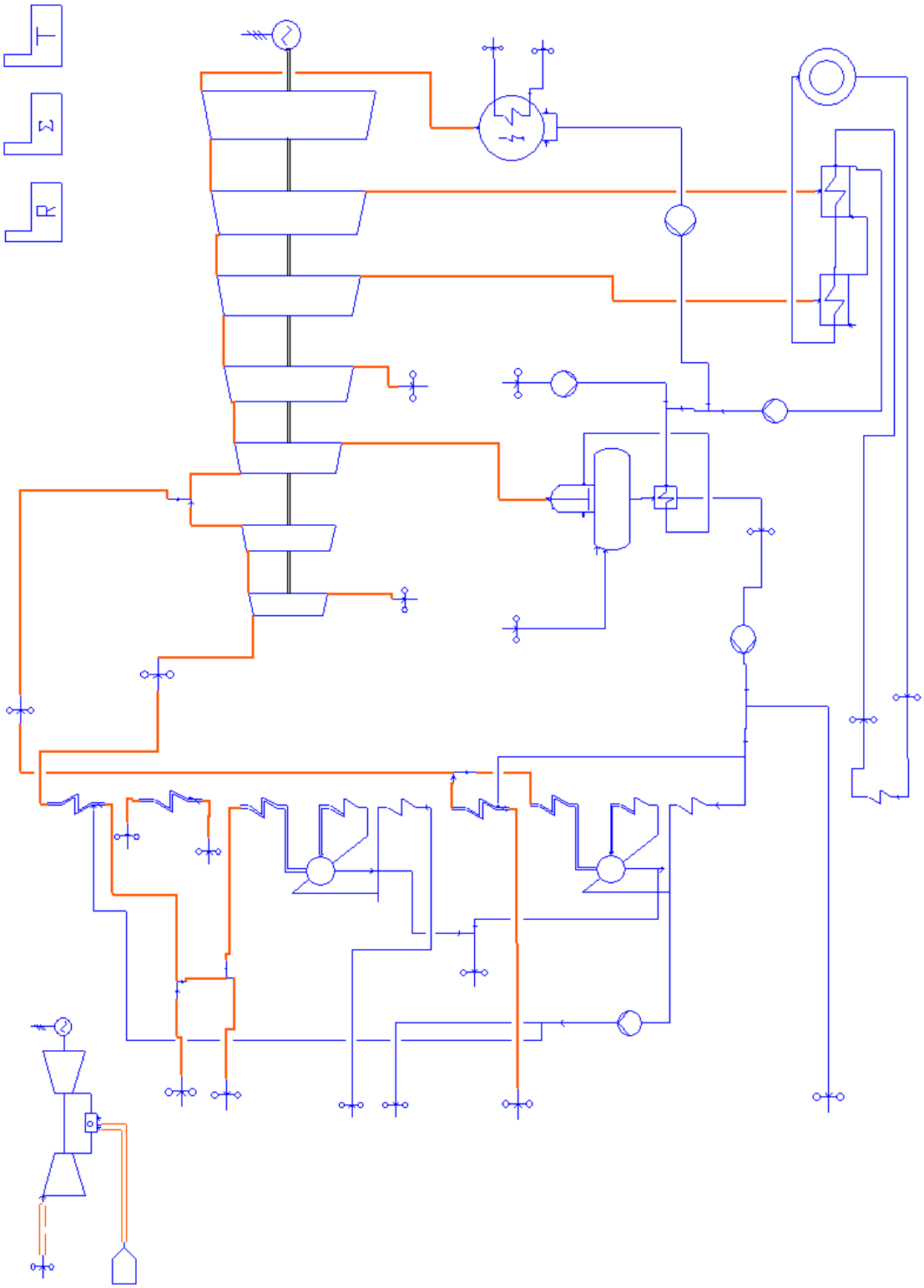
Wind Energy. 2011. Future Evolution of the Cost of Wind-Generated power. Available from http://www.wind-energy-the-facts.org/en/part-3-economics-of-wind-power/chapter-1-cost-of-on-land-wind-power/future-evolution-of-the-costs-of-wind-generated-power.html. Accessed on 5.8.2011.

APPENDICES (3 pieces)

APPENDIX 1. Cost estimate categorization. (Westney, 1997)

Phase of estimating cycle	Typical accuracy range	Typical data input available	Typical uses	Typical techniques
Class V (order-of-magnitude, rule-of-thumb)	-30% to +50%	<2% of engineering complete, general function, rough capacities and outputs	Project screening, brain-storming	Judgment or parametric including: capacity factoring, parametric cost models, gross unit costs/ratios
Class IV (top-down, predesign study)	-15% to +30%	1-5% of engineering complete, capacities and outputs, block layouts and diagrams, preliminary equipment list	Project screening, concept evaluation, feasibility studies, budget previews	Parametric including : equipment factored, gross unit costs/ ratios, parametric cost models
Class III (budget, scope)	-10% to +20%	10-40% of engineering completed, preliminary layouts and diagrams, equipment list and specifications	Appropriation or founding, design development, cost control, detailed feasibility	Mixed parametric and unit, battery limit, cascading, parametric unit cost models
Class II (definitive)	-5% to + 15%	30-60% of engineering completed, final layouts and diagrams, final equipment list and quotes, preliminary design drawings	Check or comparison; detail cost control	Unit cost or line item with minor parametric application
Class I (bottoms-up, final price)	-5% to +5%	>90% of engineering completed, design essentially complete, approved for construction	Material procurement	Unit cost or line item

APPENDIX 2. SOLVO model.



APPENDIX 3. AspenPlus model.